Evaluation of Generation Capacity Adequacy using System Dynamics

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Dedicated to my wonderful children and beloved husband.
Dedicated also to University of Canterbury and the beautiful garden city of Christchurch, New Zealand.

ABSTRACT

Most power market structures have been developed and implemented without being tested, causing major problems such as shortages and blackouts. The main cause for these problems is the inability of some markets to provide adequate stimulus for new generation investments. The installed generation capacity goes through boom and bust cycles, exposing consumers to potential shortages during long bust periods.

With the realisation that the power market has a strong interaction with generation investment, a System Dynamics (SD) model is developed to study how the market interacts with generation expansion. The SD model also allows for market structures and policies to be evaluated before being implemented. It can be an important tool in ensuring that generation expansion is done optimally without the expense of energy security.

New Zealand's generation capacity is no exception to the boom and bust trend. Since the commencement of the New Zealand Energy Market (NZEM) in October 1996, energy shortages occurred in the winters of 2001, 2003 and 2008. As a case study, an SD model is developed to study the NZEM. The results show that under some forecasted scenarios, New Zealand is susceptible to future energy shortages due to boom and bust cycles in the generation capacity.

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LIST OF PUBLICATIONS

The following papers and posters have been presented and published, throughout the course of this research work:

Posters

Date	Title	Conference
2.9.2009	The Application of System Dynamics in Power Generation Planning (I)	University of Canterbury Postgraduate Showcase 2009, Christchurch, New Zealand
19-20 November 2009	The Application of System Dynamics in Power Generation Planning (II)	New Zealand Postgraduate (NZPG) Conference 2009, Wellington, New Zealand

Conference papers

Date	Title	Conference
19-20 August 2008	The Development of Electricity Supply Industry in Malaysia	Universiti Tenaga Nasional (UNITEN) Graduate Student Conference on Research and Development 2008, Putrajaya, Malaysia
7-8 December 2009	National Energy Policies and the Electricity Sector in Malaysia	International Conference of Energy and Environment 2009, Malacca, Malaysia
17-19 June 2010	The Development of a System Dynamics Model for Electricity Generation Expansion in New Zealand	Electricity Engineer's Association (EEA) Conference 2010, Christchurch, New Zealand
19 August 2010	The Application of System Dynamics in Electricity Planning	APEX 10 Southern Summit, Christchurch, New Zealand
5-8 December 2010	The Development of a System Dynamics Model to Evaluate Electricity Generation Expansion in New Zealand	20th Australasian Universities Power Engineering Conference (AUPEC 2010), Christchurch, New Zealand
20-23 March 2011	Evaluating the Impacts of Generation Capacity Cycles in New Zealand	2011 IEEE[1] PES[2] Power Systems Conference & Exhibition (PSCE 2011), Phoenix, Arizona, United States of America (U.S.A)
19-23 June 2011	Evaluation of the New Zealand Electricity Generation Expansion in Meeting Dry Year Demands	2011 IEEE PES PowerTech, Trondheim, Norway
23-24 June, 2011	The impacts of generation mix on New Zealand's susceptibility to dry year shortages	2011, Electricity Engineers Association Conference, Auckland, New Zealand

[1] Institute of Electrical and Electronics Engineers

[2] Power and Energy Society

NOMENCLATURES

Abbreviations	**Details**
APR	Annual Planning Report
BETTA	British Electricity Trading and Transmission Arrangements
BETTA	British Electricity Trading and Transmission Arrangements
CalISO	California ISO
CPUC	California Public Utilities Commission
CM	Capacity margin
CEGB	Central Electricity Generation Board
CCGT	Combined cycle gas turbine
COMIT	Commodity Information and Trading
CPI	Consumer Price Index
DistCos	Distribution companies
ERCOT	Electric Reliability Council of Texas
ESP	Electric Service Providers
EPPAM	Electric Utility Policy and Planning Model
EC	Electricity Commission
ECNZ	Electricity Corporation of New Zealand
M-Co	Electricity Market Company
ESI	Electricity supply industry
ETS	Emission Trading Scheme
ECM	Energy capacity margin
ENTSO-E	European Network of Transmission System Operators
ETSO	European Transmission Operators
FIR	Fast Instantaneous Reserve
FERC	Federal Energy Regulatory Commission
GAMS	General Algebraic Modeling System
GEM	Generation Expansion Model
GXP	Grid Exit Point
GIP	Grid Injection Point
HVDC	High Voltage Direct Current
IPP	Independent Power Producer
ISO	Independent system operators
ICP	Installation Control Points
IGCC	Integrated gasification combined cycle
IEM	Internal Electricity Market
IAEA	International Atomic Energy Association
ISO-NE	ISO New England
JASP	Jiaotong Automatic System Planning Package
LMP	Location Marginal Pricing

LRMC	Long range marginal cost
MDS	Market development scenario
MARIA	Metering and Reconciliation Information Agreement
MISO	Midwest ISO
MIP	Mixed integer program
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NZEECS	National Energy Efficiency and Conservation Strategy
NEMS	National Energy Modelling Systems
NGC	National Grid Company
NETA	New Electricity Trading Arrangements
NETA	New Electricity Trading Arrangements
NYISO	New York ISO
NZEM	New Zealand electricity market
NZES	New Zealand Energy Strategy
NI	North Island
OASIS	Open Access Same-Time Information System
OCGT	Open cycle gas turbine
O&M	Operation and Maintenance
PJM	Pennsylvania-New Jersey-Maryland
PPP	Pool Purchase Price
PPA	Power Purchase Agreement
PIES	Project Independence Evaluation System
RTO	Regional Transmission Organisations
RMA	Resource Management Act
SPD	Scheduling, Pricing and Dispatch
SRMC	Short run marginal cost
SIR	Slow Instantaneous Reserve
SI	South Island
SPP	Southwest Power Pool
SOE	State Owned Enterprise
SOO2008	Statement of Opportunities 2008
SOO2010	Statement of Opportunities 2010
SCI	Statements of Corporate Intent
SD	System Dynamics
TSO	Transmission system operators
U.K.	United Kingdom
U.S	United States
WIGPLAN	Westinghouse Interactive Generation Planning
WASP	Wien Automatic System Planning Package

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1 INTRODUCTION

This thesis commences with the background information and objectives for this research. The second section of this chapter describes the thesis layout.

1.1 General background

The electricity supply industry (ESI) in each country is unique due to its history, geography, natural resources, economics and politics. Power system technologies, international commodities, have been significantly improved over time. Prior to the ESI restructuring, most developed countries reached a reliability of having nearly zero supply interruption. Engineering tools and programs were developed and proved useful in ensuring the technical reliability of the system.

Many developed countries have restructured their ESI to become market driven rather than centrally planned and regulated. Restructuring of a country's ESI is a very complex exercise based on national energy strategies and policies, macroeconomic developments and available natural resources, and hence its application has varied from country to country. There is no single solution applicable to all countries and there is a broad range of diverse trends (Lai 2001).

However, the restructuring changed the system's behaviour and called for some changes in the way the system was planned and operated. Blackouts and shortages were observed in some countries, highlighting the need for better understanding of the evolved system. Even though generally the utilities' physical structure (power stations, transmission and distribution network, etc.) remained unchanged with market deregulation, the ESI began to be operated and managed differently in order to maximise profit. As a result, in order to maintain the system's reliability, the concerns were no longer on technical considerations alone, but on market components as well.

Under the market mechanism, the wholesale market price plays an important role in infrastructure development. The market becomes an indicator in determining whether a new generation investment is required. A consistently high wholesale market price indicates a small difference in electricity supply and demand, signalling the need for new generation capacity to meet the demand. The high prices encourage investors to build new power plants to provide the required energy to consumers. When new generation capacity is commissioned, the wholesale market price becomes lower to reflect the supply adequacy or surplus in meeting the load demand.

One of the difficulties faced by the restructured ESI is to deliver the correct level of generation capacity. Generally, when an ESI is restructured into a competitive market model, a decline in generation capacity is observed because investors wait for the suitable time they perceive would give them most profits. The suitable time is generally when the margin between supply and demand is small enough to require an increase in supply. This is signalled by a high electricity price which offers investors a high return on their investment. Depending on load growth and power plants decommissioning, the interval to reach a suitable time for investment is uncertain. Given a long lead time for power plant development, there is also no certainty that investors will react to the market signal for new investments in time to meet the demand. The decline in the generation capacity is known as a bust period. Electricity shortages have been observed in several countries during their ESI bust periods.

A bust period is usually followed by a boom period because when the margin between supply and demand is small and the electricity price becomes high, several investors will decide that it is a suitable time for them to invest, and as a result, several power plants are built. The absence of coordination among investors can result in surpluses of supply during boom periods. Investments usually cease after the boom period until the margin between supply and demand narrows again and another suitable time for investment arrives. The wait for another suitable investment time can lead to another bust period. This alternating pattern of boom and bust periods are known as the boom and bust cycles. It has been observed in many commodity markets and with the restructuring of the ESI into a competitive market, the trend can be observed in the ESI as well.

The observation of boom and bust periods in the ESI indicates that the relationship and interaction between the market price and generation investment is important and should not be ignored in studying generation expansion. Hence, it is useful to have a model that can analyse these interacting components of the ESI. System Dynamics (SD) modelling has been proven to be a useful tool of studying the interactions of multidisciplinary factors (Forrester 1961). SD is a type of behavioural simulation model. It is a descriptive modelling method based on explicit recognition of feedback and time lags (Forrester 1961; Sterman 2000). Rather than model the electricity supply and demand using the concept of cause and effect, SD captures a more realistic dynamic relationship between them by incorporating feedbacks.

1.2 Research objectives

New Zealand's ESI was restructured in the late 1980s. Since then, electricity supply shortages have occurred in the winters of 2001, 2003 and 2008. It was suspected that these shortages were due to boom and bust cycles of generation capacities. To analyse these issues further, this research developed an SD model to study the electricity market and generation expansion in New Zealand. It was anticipated that the research would be able to use the model to answer the following questions:

i. Will capacity cycles continue to occur in New Zealand's ESI under the current NZEM structure?
ii. Will the capacity cycles cause any energy shortages?
iii. Will the capacity cycles cause any supply security constraints[1]?
iv. What are the important factors that influence the capacity cycles and how do they impact energy and supply security?

In an attempt to answer these questions, the SD model was used to simulate five different possible future market development scenarios that have been developed by the Ministry of Economic Development of New Zealand. The forecasted generation capacity results from the SD model were then compared with the results from the Generation Expansion Model (GEM). GEM is a model that has been developed by the Electricity Commission (EC) of New Zealand. Their results were published in the Statement of Opportunities 2008 (SOO2008).

The SD model was then extended further to investigate if any electricity shortages will occur in the future. A new parameter known as "Energy Capacity Margin (ECM) has been introduced and is used as a measure for

[1] Electricity supply security is jeopardised when the supply is unable to meet peak demands. This is elaborated further in section 3.1 of Chapter 3.

energy adequacy. Electricity supply security constraints are also evaluated by calculating Capacity Margins (CM) from the forecasted generation capacities. Sensitivity analyses were done using the SD model to study the impacts of several factors on generation expansion and energy security.

1.3 Thesis Objective and Layout

The main objective of the thesis is to present and discuss the results of this study. Initially, it provides some background on ESI structures prior to and after restructuring. It then highlights the issues that are addressed by the research. It also provides the theoretical background that is required in forming the SD model. The model development and verification is then described in detail. The model simulation results are presented and explained. The research conclusions are then discussed.

The layout of the thesis is done as follows:

- Chapter 2 - Restructuring of the Electricity Supply Industry

This chapter starts off with providing some background on ESI restructuring. It discusses the motivations and advantages behind the structures. The wholesale competition model structures are then elaborated in detail. Some restructuring trends from different countries are briefly examined. Problems resulted from the ESI restructuring are then discussed.

- Chapter 3 – Power Generation Expansion Planning Methods

This chapter provides a discussion on generation expansion planning before and after the ESI restructuring. It then elaborates on the market interaction with generation investment. It also highlights the problems faced in some countries in maintaining the correct level of generation capacity to meet the demand.

- Chapter 4 – Research Method: System Dynamics

This chapter elaborates on the chosen research method, System Dynamics (SD). It briefly discusses other methods that have been used to study electricity market interaction with generation investment. It also includes past work which utilised SD to study various aspects of the ESI.

- Chapter 5 – Electricity Supply Industry in New Zealand

This chapter provides a brief history of the ESI in NZ with emphasis on the restructuring period. The market structure is then described in detail. The past trends of generation capacity and electricity consumptions are illustrated and discussed. The final section discusses electricity planning and energy planning in New Zealand.

- Chapter 6 - SD Model Development for Generation Expansion in New Zealand

This chapter provides a detailed description of the SD model that has been developed to study the generation expansion in New Zealand. It then explains how the model was validated using historical data.

- Chapter 7 – Simulation Inputs and Assumptions

This chapter describes the inputs and assumptions that were used to run the SD model to analyse the five different future market development scenarios.

- Chapter 8 - Results Comparisons and Discussions

This chapter compares the generation capacity results from both the SD model and the GEM model for five different future market development scenarios. The SD model also evaluates whether the resultant capacities will cause electricity shortages and security constraints. The evaluation results are discussed in this chapter.

- Chapter 9 –Sensitivity Analyses on the SD Model

The chapter discusses the results of the sensitivity analyses done on the SD model.

- Chapter 10 –Conclusions and Further Work

This chapter relates the results from this study back to its research objectives and discusses the findings. Conclusions and recommendations are provided. It also suggests some potential future work that can be done by others who wish to follow up on this study.

2 RESTRUCTURING OF THE ELECTRICITY SUPPLY INDUSTRY

The electricity supply industry (ESI) has for a greater part of the 20^{th} century, been considered to be a natural monopoly, with vertically integrated state-owned enterprises or private monopolies subject to public regulation operating all the segments of the industry. The seed for the liberalization of the industry was sown in the 1980s with the introduction of competitive markets in the generation of electricity by the entry of Independent Power Producers (IPPs). The industry restructuring has since then progressed to include electricity transmission and distribution and the creation of an electricity market (Sabai 2001). The restructuring causes massive changes in the way the ESI operates. From being heavily regulated, the industry became competitive and market driven and even left to self regulate in some countries. This chapter provides descriptions of traditional and restructured ESI and highlights the differences between them. The chapter describes the restructuring processes and provides trends from several countries. It concludes with some discussions on problems faced in the restructured markets.

2.1 Regulated ESI

2.1.1 Description and motivations

In most countries, electricity started off with private installations for industrial purposes. For example, the first recorded use of electricity in

New Zealand was in 1861 for a private telegraph line between Dunedin and Port Chalmers (Martin 1998). Later in the mid 20th century, as electricity usage became more widespread, electricity quickly turned into a necessity and became an important fuel for economic growth. As a result, in most countries, governments took over the ownership and operation of the ESI. At that time, large centralized power plants were the most efficient and least expensive method of producing electricity and delivering it to consumers. These plants took years to build and operated for 30 years or more. The need for long term planning was a major reason for government intervention and coordination in many countries. It was believed then that governments were best able to mobilize the large amounts of capital necessary to develop the sector and bear the long time horizons for the recovery of costs. Hence, most countries relied upon the government to finance, construct, own and operate the industry until the 1980s (Hämäläinen, Mäntysaari et al. 2000; Beder 2003).

The ESI was also vertically integrated where all the components of the industry from electricity generation to electricity distribution are owned and operated by the same entity, the government or private monopolies (e.g. in the U.S.). Hunt and Shuttleworth 1996 described the traditional monopoly model shown in Figure 2.1.

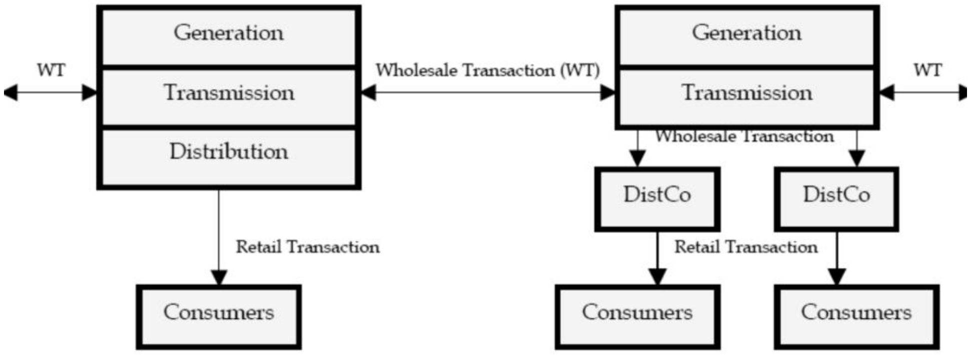


Figure 2.1: Monopoly model structure (Sabai 2001)

The monopoly model is characterized by the fact that all segments of the industry operates as a monopoly and therefore are not subject to competition. While monopoly does not necessarily mean vertical integration, the traditional monopoly model is typically categorized by a vertically integrated system where the utility owns and controls all the segments of generation, transmission, distribution and retail in an area of franchise. In some countries, the distribution segment is operated by separate entities (distribution companies (DistCos) that are given franchise rights for distribution while purchasing their entire electricity, shown on the right of Figure 2.1 (Sabai 2001). England, Wales and New Zealand had this structure prior to restructuring in the 1990s. All transactions are done internally within the monopoly company. Vertical integration of the ESI was prompted by the factors shown in Table 2.1.

Table 2.1: Factors encouraging vertical integration of the ESI

Factors	Details
Economies of scale[1] (Frank and Bernanke 2004; Sioshansi 2006)	Electricity is cheaper when supplied by large power plants rather than by small ones
Economies of scope[2] (Teece 1980; Sabai 2001; Frank and Bernanke 2004)	Similarities within the industry segments result in economies of scope, e.g. system requirements such as electrical protection and instrumentation are applicable to all transmission, distribution and generation segments
High transaction costs (Sabai 2001)	Coordinating the operation of separate segments can be expensive if they involve different players, due to the costs of negotiating, executing and litigating the required contracts
Technical coordination	Electricity cannot be stored and supply has to match the demand plus losses at all times. Electricity dispatch is easier if the flow from the generator to the consumers is done by one party
Investment incentive (Sabai 2001)	With high capital investments in the ESI, the monopoly right to operate the entire vertical segments of the industry became the motivation for investors to invest and recoup their investment by every possible means. This was the case in the U.S. where the investors were not the government but private companies.

However, as technology progresses, some of these factors are over ridden by other motivations that bring about ESI restructuring.

2.1.2 Perceived Deficiencies of the Regulated ESI

The most common argument for restructuring is the inefficiency of regulation. Ideally, consumers would like a reliable and dependable electricity supply at a minimum price. In a truly competitive market, suppliers can offer lower prices by:

[1] In microeconomics, the term 'economies of scale' refers to the reductions in cost when the size of the facility and its outputs are bigger

[2] In microeconomics, the term 'economies of scope' refers to the reductions in cost when the common and recurrent use of proprietary knowhow is used to produce two or more products

(i) holding the price down to the marginal cost or/and

(ii) minimize cost

On the other hand, a regulator can do the former or the latter but not both. It has to make a trade-off since the suppliers always know the market better than regulators. Tariffs are in most cases set by ensuring a fair return on investments (by rate-of-return price setting or cost-plus) made by the utility companies, which provide no incentives for making good investments (Stoft 2002). This is a great concern to consumers as bad investments are also compensated for (Sabai 2001).

Regulators also tend to err in the direction of driving prices down toward cost. However, generation costs vary constantly, whereas it is difficult to readjust the consumer rates too often. This results in regulatory lags that do not provide accurate incentives for suppliers to reduce their prices (Stoft 2002). While regulatory institutions are responsible for ensuring prudent investments, and operation and services are up to reasonable standards, it is often difficult for the regulators to keep a close eye on all aspects of the utility without employing a large number of engineers and economists. This factor is aggravated by the fact that regulatory institutions are often managed by civil servants who are not totally conversant with the technicalities of the very industry they are regulating (Sabai 2001).

In addition, these companies are inherently large in size and are consequently slow in adopting innovation and changes in technology.

Bureaucracy within large organizations like the utilities makes the situation worse. Also, lack of competition may result in a lack of quality in customer service. Argentina's experience where electricity prices have been reduced by 40% merely by introducing competition into the sector is evidence that the regulated monopoly status of the industry can hide within it a considerable degree of inefficiency (Sabai 2001).

However, restructuring is not equivalent to perfect competition (Stoft 2002) and has its own inefficiencies and disadvantages as well. The next section discusses the factors that pushed for the restructuring of the ESI.

2.2 Factors for ESI restructuring

In the past, the factors summarised in Table 2.2 have been used to push for restructuring in many countries.

Table 2.2: Factors encouraging restructuring of the ESI

Factors	Details
Cash generation for governments	Governments can generate a significant amount of cash by disposing of their stake in the ESI. As the capitals involved are large, the motivation to sell these assets is high, particularly for countries that are facing financial difficulties due to a stagnant or slow economy (Sabai 2001).
Depoliticizing the industry	The industry can function more efficiently when political interests are separated from economic interests. Private companies can make investment decisions solely based on economic grounds rather than to appease the political masters (Sabai 2001).
Putting an end to using the utilities to finance social objectives	The removal of the practice of taxation by regulation, cross-subsidization of tariffs, and subsidizing specific technologies could ensure that utilities operate more efficiently (Sabai 2001).
New technology	New technologies lower costs, providing affordability to private firms. Gas-turbine technology has lowered the cost of power plant construction significantly and reduced the construction period to between 12 to 18 months from the 4 to 7 years needed for conventional type plant (Sabai 2001). Other enabling technology are the information technology and internet applications that allow for power system monitoring and trading (Lai 2001). The case for competition is further strengthened by the fact that innovation in technology is best motivated by an environment of intense competition (Sabai 2001).
Availability of Private Capital	The emergence of capital and bond markets as an alternative source of funds, combined with the removal of barriers for capital flows between countries, have made it possible for private enterprises to undertake large scale projects in the infrastructure industries (Sabai 2001).
Free Market Economies	As nations move from centrally planned economies to free market economies, the role of governments is increasingly viewed as a facilitator of business rather than being involved in any form of business. Globalization and the move to encourage and impose free trade between nations through World Trade Order (WTO) agreements and trade agreements between nations has induced pressure on governments including developing countries to privatize and liberalize the network utilities industry (Sabai 2001; Beder 2003).
Public perception	The sentiment that pushes for restructuring is that public service obligations are no longer necessary (Lai 2001).

2.3 Descriptions of ESI restructuring

Restructuring of the ESI is one of the most important global energy developments of the last century (Hämäläinen, Mäntysaari et al. 2000). Before elaborating on the details, the following commonly used terminologies are defined (Sioshansi 2006):

Table 2.3:Terms used to describe ESI restructuring

Terms	Definition
Restructuring	Attempts to reorganize the roles of the market players, the regulators and/or redefine the regulations in the ESI, but not necessarily to "deregulate" the market
Liberalisation	Attempts to introduce competition in some or all segments of the market and remove barriers to trade and exchange
Privatisation	Selling of government owned assets to the private sector
Corporatisation	Attempts to make state owned enterprises (SOEs) look, act and behave as if they were for profit, private entities. In this case, an SOE can be made into a corporatisation with the government treasury as the single shareholder

The European Union refers to its restructuring efforts using the term "liberalisation". Market liberalisation can be done without privatisation, such as is done in Norway and New South Wales, Australia. In New Zealand, the generation was initially corporatized to form ECNZ. Part of the asset was then privatised to form Contact Energy. The remainder of the Electricity Corporation of New Zealand (ECNZ) was then "liberalised" further to form three separate state owned enterprises (SOEs). They vigorously compete with one another while all belong to the same single shareholder, namely the government of New Zealand. The restructuring of New Zealand's ESI is further elaborated on in Chapter 5.

The term "deregulation" is essentially a misnomer. No electricity market has been fully deregulated. Experience suggests that even well functioning competitive markets need a regulator, or at a minimum a market monitoring and anti-cartel authority. Germany and New Zealand[3] attempted to do without a regulator until recently. Restructuring' in the United States

[3] The introduction of a regulator in the New Zealand's ESI is discussed in Chapter 5.

is sometimes referred to as "re-regulation" because the resulting competitive markets have more federal regulations than the regulated markets they replaced (Borenstein and Bushnell 2000).

ESI restructuring often involves 'unbundling' – disaggregating an electric utility service into its basic components and offering each component separately for sale with separate rates for each component. It also involves the separation of ownership and operation (Lai 2001). For the ESI, the industry is unbundled into the three main sectors of generation, transmission and distribution as shown in Figure 2.2.

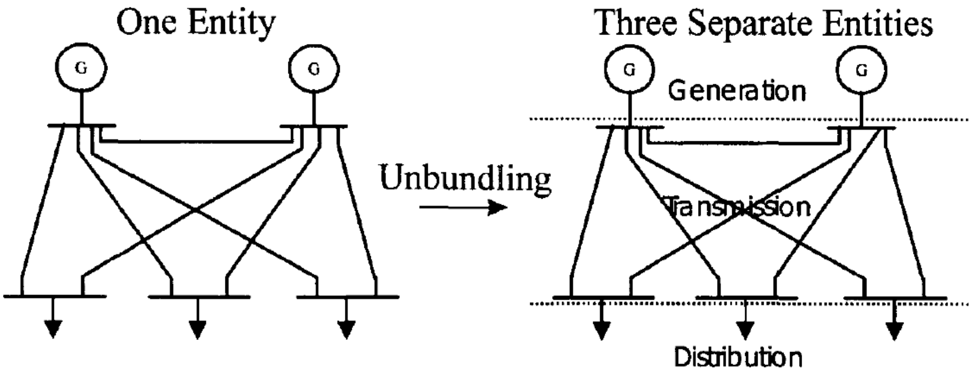


Figure 2.2: The unbundling of the ESI (Lai 2001)

Generally, when a country decides to privatise their ESI, the first sector that is sold off is the generation. The generation companies sell their energy to either a single purchaser or a wholesale market to be further dispatched through the transmission and distribution network. The transmission and distribution of electricity are done by companies owning the various lines whereby their services are paid by their respective customers. Line services in the transmission and distribution networks are still widely considered as natural monopolies[4]. Hence, usually there is only one line provider within a specified geographic region.

[4] Natural monopoly is a situation where one firm can produce a given level of output at a lower total cost than can any combination of multiple firms. It occurs in industries that exhibit decreasing average long run costs due to their size (i.e. economy of scale).

Other components which are important in maintaining the security and reliability of a restructured ESI are the system operator and the ancillary services such as frequency keeping, various types of reserves and black – start services (Stoft 2002). System operation can be done by the transmission company, as is done in New Zealand. Ancillary services are generally offered by generation companies which have the required capabilities[5] to the system operator, at certain charges.

Besides the three main sectors, most fully deregulated countries perform the sale of electricity via a competitive retail market where the customers can choose their electricity suppliers. Retailers purchase the electricity from generation companies in a wholesale market and sell it to the consumers.

2.4 General ESI structures and their evolution

In their book "Competition and Choice in Electricity", Hunt and Shuttleworth 1996 formulated that the restructured ESI market could take one of three possible generic forms. Although in practice there may be numerous variations to these models, they believed that the major concept is captured within these three models. These models are the single purchaser, wholesale competition and retail competition models. The models are defined by their degree of competition and choice (Sabai 2001).

2.4.1 Single purchaser model

The single purchaser model is the second step in the movement from a traditional monopoly model to one that introduces competition. Competition is introduced in this model in the generation services only. Choice is conferred upon the single purchaser. The main concept of the model is that a single purchaser is assigned the power to purchase electricity from

[5] The capabilities to provide the different required ancillary services depend on the types of power plants the generation companies own

competing generation companies to sell to the distributors (or directly to consumers if transmission and distribution remain integrated). Generating companies would compete to construct and operate power plants. The single purchaser undertakes its purchase by means of long-term contracts called Power Purchase Agreements (PPAs). Figure 2.3 shows the structure of the model.

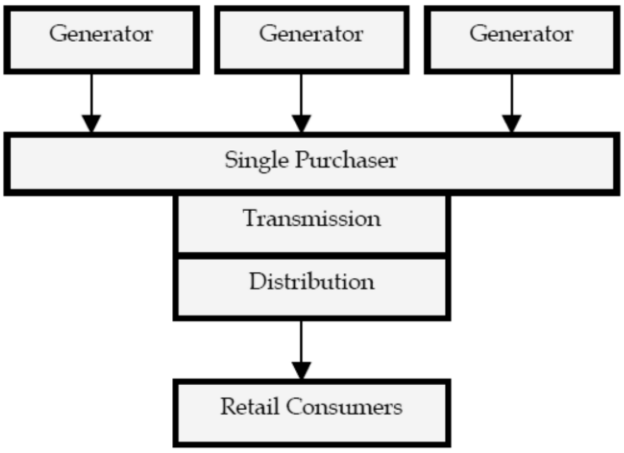


Figure 2.3: Single purchaser model structure (Sabai 2001)

The generator companies are referred to as Independent Power Producers (IPP) which may be created from existing utilities by divestiture or new entries who enter the market when new plant are required. The risk for the construction and operation of the plant lies with the IPPs, thus reducing the risk borne by the customers as is the case for the monopoly model. Since on average, roughly half of the cost of a kWh of electricity is associated with the construction and operating costs associated with power generation, this risk movement is of extreme importance to the industry and the consumers. The single purchaser model provides the opportunity for companies that are particularly good at construction and operation of power plants to expand their market and while doing so set a new standard for prudent practices upon which utilities' investment will be evaluated.

The model is particularly appealing to countries where the state is unwilling to completely divest control and ownership of the industry for strategic reasons. It is possible in this model to allow the incumbent utility to continue to have a stake in the generation segment although this may lead to discriminatory practices by the single purchaser in favour of the utility if the single purchaser is a division of the incumbent utility (Sabai 2001).

2.4.2 Wholesale competition model structure

In the case of the wholesale competition model, the only difference it has from the single purchaser model is that there are multiple distribution companies exclusively serving smaller areas. Figure 2.4 shows the structure of the wholesale competition model. The essence of this model is that the privilege of choice has now moved to the distribution companies and large consumers.

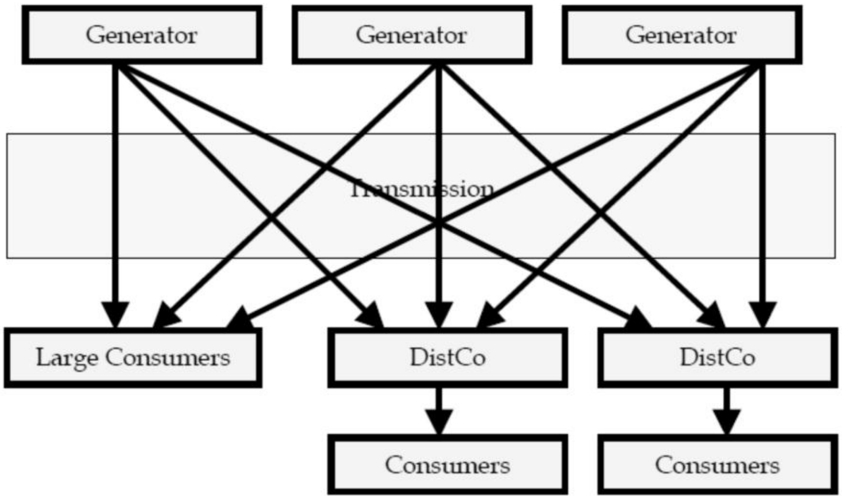


Figure 2.4: Wholesale competition model structure (Sabai 2001)

In this model, all three segments of the industry must be totally separated. Wholesale competition requires sales of electricity from generation companies to distribution companies through the high voltage transmission network, owned and operated by the transmission provider. A neutral transmission provider is required to transport electricity from the generator to distribution companies or to large consumers, a concept known as wholesale wheeling. Generation companies competitively bid to supply the distribution companies while the transmission provider charges the generator, the distribution companies or both for transport services.

In the wholesale competition model, lines companies form the only non-competitive segment that remains. With the exception of large consumers, other consumers are subjected to the price charged by the lines companies. It is therefore common to find that the transmission and distribution segment remains highly regulated and remains subjected to rate-of-return pricing (Sabai 2001).

The wholesale electricity market differs from other commodity markets because electricity cannot be stored and it is not possible to distinguish which generator produced the electricity consumed by a particular customer. Because of this feature, the wholesale electricity market uses the concept of a pool where all the electricity output from generators is centrally pooled and scheduled to meet the electricity demand. Furthermore, as it is impossible to guarantee that each generator can generate exactly the amount needed at the scheduled time to distribution companies' demand (nor can the distribution companies guarantee that it can consume the amount provided), there is bound to be considerable imbalances in the actual trading that takes place from the contracted trading. There are two distinct trading arrangements that exist today to deal with wholesale electricity markets, i.e. the Power Pool model and the Multi-Market model.

2.4.2.1 Power pool

The power pool mechanism was introduced by the England and Wales electricity industry and is characterized by a central electricity pool where generation companies sell their power to, and where distribution companies buy their power from. In the power pool model, generation companies bid to supply to the pool (grid) by spot market bidding only, which is conducted by the Market Operator (MO), typically one day in advance. Participation in the pool is mandatory for generation companies and distribution companies alike. The basic time unit for market clearing price and settlement is hourly or half-hourly slots, implying either 24 or 48 price sections per day. The system operator (SO) will dispatch generators according to a schedule based on the MO's market clearing price (defined as the price at which supply equals demand-all demand at or above this price has been satisfied, and all supply at or below this price has been purchased), and the generation companies will be paid the Pool Purchase Price (PPP). Generation companies can be paid in two ways (Stoft 2002; Evans and Meade 2005):

(i) Through uniform pricing – All generation companies receive a single uniform price, representing the price where supply and demand coincide

(ii) Through 'pay as bid' pricing – Each generator receives the prices that they bid for each unit of generation they offered to supply

Centralised wholesale markets can be set up as voluntary or compulsory. Under voluntary arrangements, parties may also trade bilaterally through mutually agreed contracts. The distribution companies can and are normally encouraged to enter into long-term bilateral financial contracts with the generation companies to hedge the price risk for both parties. These bilateral financial contracts are done outside the pool. On the other hand, in a compulsory pool, all energy trading must be done through the pool (Evans and Meade 2005; Ministry of Economic Development New Zealand 2009). England and Wales, Argentina, Australia and Singapore have adopted the power pool model.

2.4.2.2 Multi-Market mechanism

An alternative to the power pool model is the decentralised power exchange. Under the exchange, generation companies and purchasers contract bilaterally for supply and to cover any imbalances in supply and demand. Affected parties are required to pay the price differences via a balancing market, usually managed by the market operator (Stoft 2002; Evans and Meade 2005).

The Multi-Market mechanism (Nordic-style), which was first implemented in Norway and later adopted in New Zealand, California, and Spain, is more complex than the pool model. For one, it is not mandatory (it is also often referred to as a voluntary pool system) for generation companies and distribution companies to participate in a central electricity pool. Generation companies and distribution companies (also large consumers) enter into bilateral contracts and schedule their contracts through the MO. Generation companies dispatch their own generators based on their physical delivery contracts entered with the distribution companies by means of bilateral contracts. As its name suggests, there are multiple markets involved, which are the long-term physical trades, the day ahead, hour ahead balancing and real-time. The trading of most electricity is achieved by means of long-term trade-able contracts while spot markets exist to provide a degree of flexibility at the margin for an addition or reduction in power anticipated one day ahead. The balancing market provides settlement for the actual imbalances that occur from the contracted and the spot market trading.

2.4.2.3 Pools versus exchanges

There is no one simple solution in deciding a wholesale energy market structure for a country. To date, the designs of power markets are still plagued by controversies on which architecture is better. Even though the decentralised exchanges are simpler to organise, it is less efficient and reliable due to a lack of coordination. On the other hand, a pool is susceptible to gaming opportunities and can be biased and inefficient due to side payments. The complexity and non-transparency of pools can also lead to design mistakes that are hard to discover and correct (Stoft 2002).

2.4.3 Retail competition model structure

One of the difficulties faced with regulators in implementing the wholesale competition model is where to draw the boundary for a consumer to qualify as a large consumer and therefore have the ability to purchase power directly from a generator and not from a distribution company. Giving choice to all classes of consumers would prevent price discrimination by distribution companies against small captive consumers and provide consumers, as end users, the opportunity to negotiate their power purchase and obtain a better deal. It is also believed that if consumers as end users can purchase directly from the generation companies (normally through a retailer), this would open up the industry further towards competition and would ultimately result in lower prices to consumers. This is the rational for the retail competition model, which is shown in Figure 2.5. The essence of the retail competition model is that choice is now conferred to the end-user, i.e. the consumer.

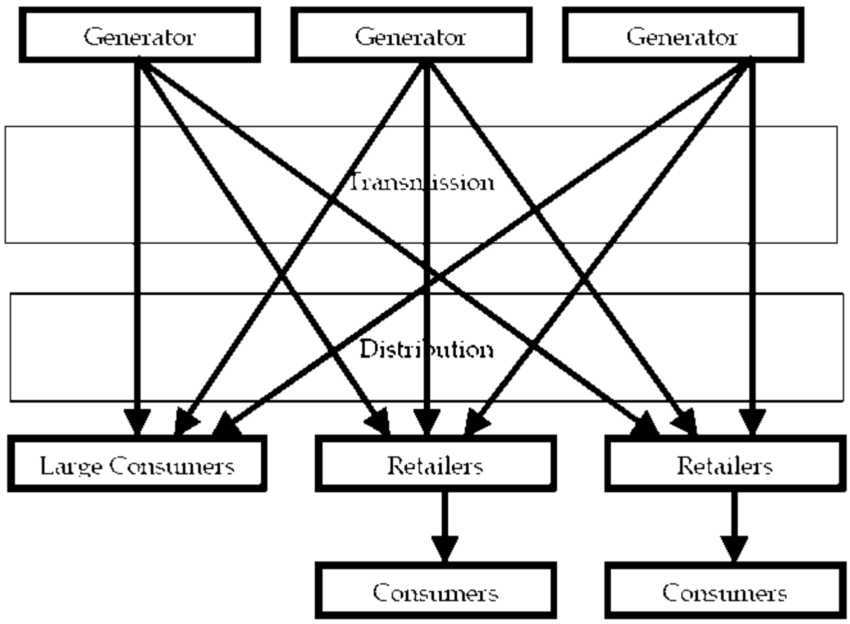


Figure 2.5: Retail competition model structure

In this model, the distribution company performs the same function as the transmission service provider that provides transport facilities, i.e. as a network company, and does not involve itself with the retail function. This is known as retail wheeling, or transporting electricity from the transmission grid over the distribution grid into homes, factories, and businesses. It therefore means that the retail function, which is subjected to competition and is unregulated, is further unbundled from the distribution function which remains regulated. The retailer functions as an aggregator of electricity. It purchases electricity from generation companies at competitive prices and schedules the transport of electricity through the transmission and distribution networks to the consumers. Consumers will be charged separately for the various components, i.e. energy, the transmission service charge, the distribution network charges and finally the retailer's commission for its services. Consumers now have the choice to switch retailers to get a better deal, which therefore introduces competition in the retailing segment, hence, the name "retail competition". Retailers too could provide options for the consumers to select the generator of their choice. This model ensures that commercial, industrial and residential electricity consumers can successfully negotiate the lowest price directly with sellers or indirectly through retailers.

2.5 Comparisons between the ESI structures

Table 2.4 summarises the major attributes of the four reform models discussed in the previous sections, whereas the benefits and deficiencies of each model are listed in Table 2.5.

Table 2.4: Summary of major attributes of ESI market models

	Monopoly	Single Purchaser	Wholesale Competition	Retail Competition
Choice is conferred on:	-	Purchaser	Retailer	Consumers
Market risk borne primarily by:	Consumers	Consumers	Generation companies/ Consumers	Generation companies/ Consumers
Obligation to supply is with:	Utility	Purchaser	Distribution companies	-
Hidden subsidies is:	Easy	Easy	Difficult	Difficult
Transaction cost is:	Low	Low	Higher	Higher
Incentives to lower cost is:	Low	Moderate	High	High

Table 2.5: Benefits and deficiencies of the reform models (Sabai 2001)

Model	Benefits	Deficiencies
Monopoly	• Economies of scale • Easier to implement social development objectives • State has better control • Low transaction cost • Lower risk, therefore lower cost of capital	• No incentives for better performance • Bad investments are compensated for • Poor accountability • Risk is carried by customers • Customers are not given any choice • Industry can be politicised
Single Purchaser	• Efficient construction and operation of power plant • Relatively low transaction cost • Low risk therefore lower cost of capital • Attractive to investors	• Customers are not given any choice • Customers bear most of the risk • Policing the PPA is difficult
Wholesale Competition	• Efficient construction and operation of power plant • Competition may result in lower price to consumers • Generation is depoliticised	• Higher transaction cost • Need for efficient IT and on line metering • Market power in generation may hurt consumers
Retail Competition	• Efficient construction and operation of power plant • Competition may result in lower price to consumers • Consumers have the ultimate choice of supplier • Industry is completely depoliticised	• Higher transaction cost • Need for efficient IT and on line metering • Market power in generation may hurt consumers

2.6 Reform process

The ESI market reform is generally done in various stages in time and follows a sequence of phases. The phases are summarised from (Sioshansi 2006) and are as follows:

i. Phase 1: Acknowledgement of problems and/ or deficiencies associated with the existing system - Common perceived problems are like gross inefficiencies in the ESI operations or performance, poor system reliability, high prices and supply inadequacies.

ii. Phase: A debate is made on what dysfunctional and how best to fix it – In most cases, new laws must be passed and the organisation of the ESI must be changed before a new market structure can be implemented.

iii. Phase 3: New market rules and institutions are implemented – In many cases, technically sound principles do not translate well in practice, resulting in problems and chaos.

iv. Phase 4: On-going process, generally starts with the realisation that the introduction of the initial market reform initiatives did not necessarily or automatically lead to many of the expected benefits and outcomes – In nearly all cases, initial market reform has led to unforeseen and unintended consequences, which must be addressed in subsequent "reform of the reforms" (Sioshansi and Pfaffenberger 2006). The process of modifying and adjusting the original reforms continues in most markets.

2.7 Hybrid Markets

There is general recognition that, in many parts of the world, electricity markets have evolved, or are evolving, into hybrid forms, where they are not completely unbundled, privatized, nor fully competitive. Text-book prescriptions of integrated markets with decentralized players are not necessarily the norm. In the U.S., for example, a relatively vibrant and competitive wholesale market has evolved despite the fact that most consumers continue to receive service under capped, regulated tariffs that do not reflect variations in hourly prices in the wholesale market.

Hybrid markets fall into three basic varieties (Sioshansi 2006):

(i) Markets that have been liberalized but are not fully privatized, as in some European markets or in Australia;

(ii) Markets that are privatized but are not fully liberalized, in the sense that competition is restricted, and

(iii) Markets that, in theory, are privatized and behave competitively but the government or the regulator routinely intervenes in the decisions of the market players, e.g., regarding prices or investment.

In some cases, the current hybrid status may be regarded as a mere transitory stage. In other markets, however, there does not appear to be even an intention and/or the means of moving towards a fully liberalized state. In these cases, policy makers must contend with a mixed bag of regulated, state-owned, and vertically integrated companies operating side by side with competitive, private, and unbundled companies on a distinctly uneven playing field. Some hybrid markets appear to be stuck in a no man's land, no longer fully regulated nor fully competitive, where some segments remain state-owned while others are in private hands, where some decisions are made by regulatory fiat while others are left to private investors and markets. Scholars are divided on how serious a problem this may be. In some cases, such as Australia, competition among the players remains vibrant and the problems do not appear to be serious.

However, two decades after the introduction of market reform, many previously unbundled companies have re-bundled, usually by combining generation with retail business. Moreover, there is empirical evidence to suggest that such combinations are efficient, can manage risks and price volatility better, and may be preferred by investors. Additionally, there is evidence, not universally accepted, that vertical integration – despite its obvious shortcomings – might have offered economies of scale after all. Faced with the new evidence, scholars are examining issues related to vertical integration, industry ownership, and organization.

2.8 Global restructuring trends

England and Wales embarked on a major privatization and liberalization scheme in 1989, which has been widely studied and copied (Sioshansi 2006). The basic structure, with variations, has been repeated in a number of countries. Generally, pioneers of the power system restructuring in different continents of the world embrace the idea of introducing competition in the wholesale supply and purchase of electricity combined with an open access regime for the use of electricity networks (Zhang 2010). The diversity of approaches can be seen in looking at some examples worldwide as discussed in the following sections.

2.8.1 Great Britain

The British market has gone through at least three distinct reform stages, from the original, central, mandatory pool in 1989 to the New Electricity Trading Arrangements (NETA) introduced in 2001, to the British Electricity Trading and Transmission Arrangements (BETTA), introduced in 2003 (Sioshansi 2006). The details on the pool and NETA market mechanisms are provided by Lai et al (Lai 2001) and Beder (Beder 2003).

The reform commenced in 1989 with the breakup of the Central Electricity Generation Board (CEGB) into one transmission company, National Grid Company (NGC) and three generation companies - National Power, PowerGen, Nuclear Electric. The distribution networks were privatised into twelve regional electricity companies, with each being effectively a combination of a distribution company and a retail company. They compete independently to buy power from the generation companies through a mandatory power pool. The daily power pool commenced on 1 April 1990 (Sabai 2001) and was operated by NGC. The Pool was then replaced by NETA in 2001 which established a framework for bilateral trading and power exchanges. BETTA then commenced in 2005 to extend NETA to the regions of Scotland so that one single wholesale electricity market is for the whole of Great Britain (Zhang 2010).

2.8.2 Nordic countries

The ESI of the Nordic countries includes Norway, Sweden, Finland and Denmark. Norway was the first Nordic country introducing market competition in June 1990 (Lai 2001). The Swedish restructuring was decided in 1995 leading to the establishment of a common Norwegian-

Swedish Exchange (Nord Pool). This electricity market completely opened to trade across national borders starting in 1996. Finland joined the common market in 1998 followed by West Denmark in 1999 and East Denmark in 2000. It is currently the only truly international market. It has one market operator (Nord Pool) and five system operators (Zhang 2010).

2.8.3 Continental Europe

The liberalisation in the EU has been a top down process driven by the directives of the European Parliament and of the Council. The directives lay down the general principles and conditions to assure the creation of a single Internal Electricity Market (IEM) in Europe. The first liberalisation was enforced in 1996 to unbundle activities in the ESI. IEM is divided into submarkets according to the control zones of the various transmission system operators (TSO). Most wholesale trade volume there is, trades bilaterally in forward and over the counter types of markets. Most consumption portfolios are covered by long term and forward contracts. A small fraction of the trade volume is traded in daily or even hourly contracts in the spot markets due to incomplete predictability of real time consumption. Although member states of the EU have similar electricity market architectures, these markets are weakly integrated across national borders. The association of European Transmission Operators (ETSO) was founded in 1999 in response to the emergence of IEM. It was then integrated into a larger association in 2009 and was called the European Network of Transmission System Operators (ENTSO-E). ENTSO-E pursues the cooperation of the European TSO and has an active and important role in the European rule setting process in compliance with EU legislation. To improve cross border exchanges, a compensation mechanism for cross border flows of electricity, the setting of guidelines and principles on cross border transmission charges and the allocation of available transmission capacities between national transmission systems were developed (Zhang 2010).

2.8.4 Australia

The reform of the Australian ESI commenced in the early 1990s. Separate commercial structures have been developed for the monopoly transmission and distribution functions and the competitive generation and retailing functions of the industry. The major reform in the Australian ESI involved the establishment of the National Electricity Market (NEM) that operates in southern and eastern Australian regions. The NEM operates in the states of New South Wales, Victoria, Queensland, South Australia, Tasmania and the Australian Capital Territory. The market operator for the NEM is the National Electricity Market Management Company (NEMMCO). It was established in 1996 to fulfil the roles of both market and system operator of the NEM. It is responsible for generator dispatch, reliability management and financial settlement in the NEM. The owners of the company are the five states and the territory within which the NEM operates. The NEM operates one of the world's longest interconnected power systems. The NEM comprises a spot market with energy traded through a commodities type pool and a spot price set every 5 minutes by the most expensive generator selected to run. The interconnection constraints within the NEM regions can cause the marginal spot prices to separate (Zhang 2010).

2.8.5 United States of America

In the U.S., the Energy Policy Acts of 1992 launched a national effort to restructure the ESI to allow greater reliance on markets. The Federal Energy Regulatory Commission (FERC) took the lead in 1996 by opening the access to the electric transmission grid via Order 888 (Beder 2003). This triggered the formation of independent system operators (ISO) including the California ISO (CalISO), New York ISO (NYISO), ISO New England (ISO-NE), Pennsylvania-New Jersey-Maryland (PJM), Midwest ISO (MISO), Southwest Power Pool (SPP) and Electric Reliability Council of Texas (ERCOT). The ISOs have the responsibility of ensuring the reliabilities of their control areas and to post the information of the available transfer capabilities of their major transmission paths on an Open Access Same-Time Information System (OASIS). Bilateral trades are then facilitated by submitting transmission requests to the control areas whose networks are used for the energy transactions.

There was an intense debate regarding the bilateral model and the pool model of market design in the mid-1990s. Meanwhile a few ISOs that had a background of operating as power pools started creating voluntary spot markets. The uniform or zonal pricing approach was initially adopted in these markets, such as the 1997 PJM market and the 1999 ISO-NE market. FERC Order 2000 encouraged the formation of Regional Transmission Organisations (RTO) which had larger authorities and responsibilities than the ISOs to oversee a region to ensure proper market operations and system reliability. In 2000, California had its electricity crisis which demonstrated that power interruptions or blackouts can significantly impact the economy, and market design and reliability assurance are closely related issues and should not be addressed separately.

At the same time, an alternate market model based on Location Marginal Pricing (LMP) and the concept of a multi settlement system with financial transmission rights as a financial instrument to hedge against transmission congestion risk, had emerged in North America. Since then, more RTOs/ISOs started to follow a similar market model and later enhanced their wholesale energy only markets with ancillary service markets. The deregulated ESI had recognised that system reliability is an integral part of a properly designed electricity market and ancillary services should be simultaneously co-optimised with energy (Zhang 2010).

2.9 Problems with restructured markets

While market reforms have addressed many of the shortcomings of the regulated or centrally planned era, they have introduced new problems (Sioshansi 2006). Currently, most if not all, ESI market designs are implemented without any explicit testing (Doorman and Botterud

2008). Untested market designs cause real world market failures[6]. Woo et al. (Woo, Lloyd et al. 2003) analysed electricity market reforms in the UK, Norway, Alberta (Canada) and California (USA) and concluded that the introduction of a competitive generation market has failed to deliver a reliable service at low and stable prices. They attributed the failure to the following factors:

- market power abuse by a few dominant sellers (especially at times of transmission congestion)
- poor market design that invites strategic bidding by suppliers
- the lack of consumer response to price spikes
- capacity shortage caused by demand growth not matched by new capacity
- thin trading of forward and futures contracts that are critical for price recovery and risk management

Even though the theory of market supply and demand has long been established as one of the fundamental theories of economics, there are some unique characteristics with electricity that makes it difficult to completely liberalise the ESI with market forces. Some of these unique characteristics are (Stoft 2002):

a) Electricity is consumed continuously by essentially all customers at all times
b) Electric energy cannot be stored easily and economically

These physical properties result in a product whose marginal cost of production and delivery cost fluctuates rapidly. Electricity demand is also inelastic, where the demand is not responsive to the change in prices. This forms a severe market flaw (Stoft 2002). The power system is also complex, where it extends over long distances and must have all its components synchronised. The voltage has to be maintained within a 5% limit at all locations to avoid system failure or blackout (Stoft 2002).

[6] Market failure occurs when freely functioning markets fail to deliver an efficient allocation of resources

Another problem that happens in a deregulated market is market power[7]. Market players are quick to take advantage of market design flaws. One of the conditions for perfect competition is that the price of electricity is not determined by the amount generated by the generation companies. In other words, generation companies do not have market power and therefore cannot control the price. However, in reality, this assumption is invalid because most generation companies can exercise market power and control the price of electricity. For example, during peak electricity usage time when the difference between supply and demand is small, a generator can have extreme market power because it is the only one capable of meeting the demand. It can then set any price for its generated supply and this must be paid by the consumers. Market power has been a major impediment to price reduction in the England and Wales Pool and the Californian Pool in the past (Lai 2001).

2.10 Chapter summary

The deficiencies associated with the traditional monopoly structure of the ESI have led to the industry's restructuring in the late 1980s. Globally, several market structures have emerged and the most liberal structure is the "Retail competition model" structure. However, the new structure does not come without any problem. Problems such as abuse of market power and supply shortages have caused many markets to be refined or redesigned. Despite considerable experience gained in the last two decades, a number of contentious market design and implementation issues still remain.

[7] Market power refers to conditions where the providers of a service can consistently charge prices above those that would be established by a competitive market

3 POWER GENERATION EXPANSION PLANNING METHODS

This chapter discusses generation expansion planning methods before and after ESI restructuring. After providing the important aspects of generation expansion planning, the different approaches taken before and after ESI restructuring are discussed.

Generation expansion planning refers to the long term planning process to expand the generation capacity to keep up with the increasing demand. Under a regulated monopolistic environment, this was done by the relevant government department. However, after the ESI has been deregulated, the generation expansion planning lies on individual investors, driven by the profit incentives provided by the market.

3.1 Fundamentals of generation expansion planning

Power system planning and investment process consists of three main stages (Sullivan 1977):

a) the development of a load forecast
b) the analysis of generation requirements (based on the load forecast) including reliability, sizes and timing of new investments and
c) the use of power flow studies and reliability analysis to decide where and when transmission should be built or upgraded.

Each of the stages is sequential, with the overall goal of the process to ensure reliability of supply at least cost (Newham 2008).

The aim of generation planning is to seek the most economical generation expansion scheme achieving a certain reliability level according to the forecasted demand for a certain period of time. In any generation expansion planning, the following questions are to be answered (Wang and McDonald 1994):

a) When to invest in new generation units?
b) Where to invest in new generation units?
c) What type of generating units to install?
d) What capacity of generating units to install?

The investment timing is crucial in ensuring that the required generation capacity is available when needed. If investment is delayed, shortages can occur and if prolonged, may cause severe economic and social impacts. If investment is too soon, then the capital is stranded without the capacity being utilised.

The plant location is influenced by the energy resource location and the transmission costs. Thermal plants need to take into account the transportation aspects in determining their location. For example, a coal plant might need to be near the sea with port access if the coal has to be imported by ship from abroad. A hydro plant is usually in remote places where the available hydro resources are. Ideally the plants have to be near an existing transmission grid network to reduce the cost of constructing new power lines.

The plant type is an important consideration in determining its usability and investment risks. The plant capacity depends on the forecasted demand and when it needs to generate electricity. Electricity is a unique commodity in the sense that it cannot be stored and must be produced simultaneously with demand. Since load varies considerably across an hour, day, and year, the electricity generation from power plants must match demand (and system losses) at all times. ESI has traditionally recognized three different classifications for power plants: base load generation, intermediate or cycling generation, and peaking generation.

Base load generators are operated at a continuous rate to service minimum system load. Generally, base load plants have high capital cost but low fuel operating cost. While these units are the most efficient to operate, they are costly to start up from a cold shut down, therefore, they are usually run at a near-constant rate. Intermediate load plants are brought online during periods of forced or planned outage of base load units. They can also be used to bridge the dispatch of base load and peaking units during periods of unusually high demand. Peaking units are plants that have the ability to generate electricity immediately and serve temporary spikes in demand, such as during a heat wave when residential and commercial air conditioning demands begin to surge.

In the past, electric utilities dispatched generating units to meet demand on a lowest- to highest-cost basis. This form of dispatch is commonly referred to as "economic dispatch." The marginal or incremental cost of dispatching units is traditionally the benchmark used to rank order available generators. These marginal costs, in the very short run, are typically associated with changes in fuel costs and other variable operating and maintenance (O&M) costs. Historically, base load units, almost always large capacity coal, hydro, or nuclear generation units, had the lowest marginal costs per kWh generated and were dispatched first to meet load. In New Zealand, geothermal power plants are also used as base load units. As load increased during the day, or across seasons, less efficient intermediate or cycling units, which generate electricity at slightly higher costs, were brought online. Peaking plants have relatively low fixed costs per kW of capacity but relatively high marginal cost per kWh generated. Peaking units would be the last types of units brought online under an economic dispatch regime. The cost of the last dispatched unit therefore defines the system marginal costs, often referred to as the system "lambda." With increased generation from renewable resources, some grid operators dispatch their renewable plants first to utilise the free energy resources, and supplement their variation in the supply (since nature is uncontrollable and varies with time) with other conventional plants.

Besides supplying electrical energy for consumption, power plants also have other functions in maintaining the supply security and integrity. These functions are summarised in Table 3.1. Not all generating units are capable of doing all the functions, and hence these functions have to be accounted for at the planning stage.

Table 3.1: Other functions of generation unit

Function	Role	Generating unit type
Frequency control	To help regulate the power system frequency (50 or 60 Hz). A change of $\pm 5\%$ can cause a cascaded system failure[1]	Generating units with free governor action[2]
Voltage and reactive power control	The voltage has to be regulated within a certain limit to avoid damage to connected appliances	Synchronous generator that is capable of generating or absorbing reactive power. Most generating units are of this type but large reactive power control requires additional investment during plant construction
Black start capability	To provide standby generating facility to generate enough power to support the running of the main generating unit's auxiliary plant in the case of total power system collapse (e.g. during a national blackout)	Generating units that are able to start up and generate by themselves without depending on external power

3.2 Plant technology and its impacts on planning

Based on how the power plant is planned to be operated and utilised, the relevant fuel and technology can be decided. Open cycle thermal plants are typical peaking plants since they have a short start-up time and are able to respond quickly to the change in energy demand. However, they have low thermal efficiency and generally run on expensive fuels, so they

[1] One unit tripping can cause the frequency to fall, which leads to another unit tripping, which lowers the frequency even further and causes other generators to trip. This is commonly known as cascade failure and could lead to a blackout

[2] The generating unit spins at partial or zero output to act as a standby in the case of frequency drop. This is known as spinning reserve

are not economic to run on a long term basis. Base load plants, in contrast, have lower marginal costs per kWh generated. Generally, base load plants are made up of large hydro, nuclear or combined cycle gas turbines. Table 3.2 shows the qualitative comparison between different generation technologies.

Table 3.2: Qualitative comparison of generation technologies (Sabai 2001)

Technology	Lead time	Capital cost/kW	Operating cost	Fuel cost	Carbon emissions
Open Cycle Gas Turbine (OCGT)	Short	Low	Low	High	Medium
Combined Cycle Gas Turbine (CCGT)	Short	Low	Low	High	Medium
Coal	Long	High	High	High	High
Nuclear	Long	High	High	Low	Nil
Hydro	Long	High	Low	Nil	Nil
Wind	Short	High	Low	Nil	Nil
Geothermal	Short	High	Low	Nil	Nil

The plant type and technology have an important influence in generation planning. Gas-fired technologies have relatively low capital costs and short lead times, providing significant advantages to investors. On the other hand, natural gas price uncertainty remains a large risk to the investor.

Nuclear power plants, by contrast, have a relatively low proportion of fuel and operating costs but high capital costs. Furthermore, economies of scale have tended to favour very large plants (1000 MW and above) resulting in a relatively large capital commitment to a single construction project and hence associated investment risk. Newer designs are more flexible with regard to operations. The potential economic advantages of building smaller, more modular nuclear plants are also being explored by some nuclear power plant designers. However, potential hazards from radiation remain a public concern.

Coal power projects have also tended to become more capital-intensive to take advantage of economies of scale, to meet tighter environmental standards more economically, and to improve fuel efficiency. As with nuclear plants, lead and construction times for coal-fired power plants can be long. Large capacity hydro plants also demand substantial lead times and are exposed to considerable risks during their construction phase as the length of a project can be subject to delays, the construction costs can also change and increase the total costs of a project. Their operation by contrast, can be highly flexible, enabling an advantage to be taken of market conditions to optimise profitability. Variation in rainfall quantity is another risk factor. Wind plants have some very attractive low-risk characteristics, including very short lead times, no fuel costs or emissions, and low operating costs. However, the variability of output of wind power reduces the value of the power produced.

Besides the factors above, resource availability is also becoming a serious consideration in planning for a power plant. Fossil fuels, which have been a major electricity resource in many countries, are believed to be depleting. This has encouraged research and innovation to explore more renewable resources and to tap them for electricity generation.

3.3 Power system planning under a regulated ESI

Dyner and Larsen described the ESI under the regulated traditional monopoly model as having stable prices, information sharing across the ESI sectors and predictable demand forecast (Dyner and Larsen 2001). This reduces the uncertainties in the variables that influence generation planning.

3.3.1 *Power system planning methods*

Power system planning under a regulated ESI is usually conducted under the guidelines of national economic planning and energy resources policy (Wang and McDonald 1994). These policies determine the development planning of energy resources planning in order to investigate comprehensively the effective use, coordination and substitution relationship of various primary energy resources such as coal, hydro and natural gas. The reason that motivates the government to administer the ESI was because electricity became a very important subsystem in any national economy that fuels development growth especially in industries. In return, power system development is influenced by the future electrical demand and national long term plans. This is illustrated in Figure 3.1.

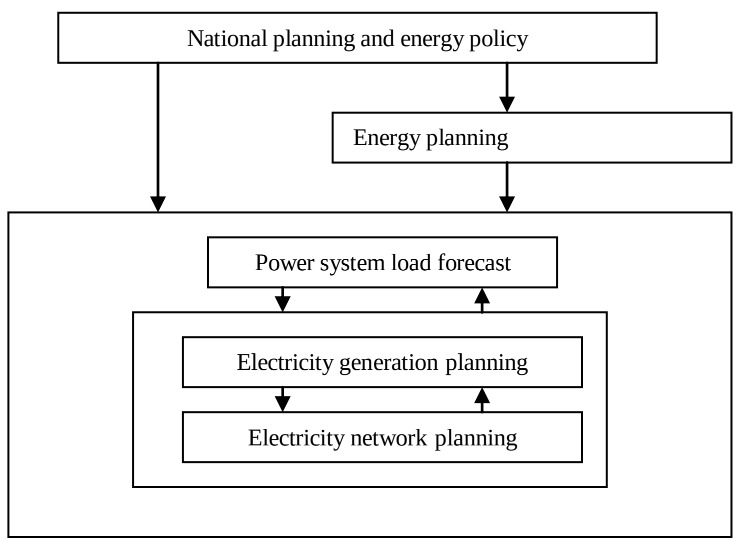


Figure 3.1: Structure of power system planning under a regulated ESI (Wang and McDonald 1994)

The load forecast forms the basis of power system planning and provides information on expected consumption increase, load curve profiles and load distribution. Generation expansion planning, which is the focus of this research, is discussed in the next sections.

3.3.2 Generation expansion planning methods

Algorithms used for generation expansion planning under the traditional monopoly structure can be broadly classified into the following three methods:

(i) The generation planning problem is divided into several constituents, which are coordinated separately. Typically, planning is divided into generation investment and optimal production simulations to reduce the dimensionality of each constituent problem

(ii) The heuristic method is used rather than the rigorous operational research optimisation method where simplifications and modifications are made. Various sources cite this method as the linear programming method, the non linear programming method and the dynamic programming method

(iii) Simplifying assumptions are made, e.g. linearisation of generation unit investment, linearisation of the coal consumption curve or sectionalized linearisation are frequently used

They are all the result of some simplifications and appropriate tradeoffs between rigour in the mathematics and the amount of computation (Wang and McDonald 1994).

An assumption that is widely adopted in several generation planning models is that all the electrical load and generating units can be considered to be on a single nodal point as far as generation planning is concerned. Some models utilizing this assumption are the Wien Automatic System Planning Package (WASP) (Department of Nuclear Energy 2010) of the International Atomic Energy Association (IAEA) and Westinghouse Interactive Generation Planning (WIGPLAN) of the American Westinghouse Electrical Company. They are known as single nodal point generation planning models. Among these models, WASP is the most widely used in developing countries for power system planning (over 100 countries) (Department of Nuclear Energy 2010). With this assumption, the model is simplified because geographical factors are not necessary in generation planning and the generating units of the same category can be grouped together. Optimisation is carried out according to the categories of generating units. However, these models are limited to the power system covering a relatively small region, with a strong transmission system in existence. To solve this problem, other models have been developed since 1980 such as Jiaotong Automatic System Planning Package (JASP) of Xi'an Jiaotong University, China.

Linear programming was one of the first optimisation techniques to be applied to the planning problem. Linear programming works well in simplified systems but fails to adequately model complex planning problems and detailed systems. With increases in complexity, the generation planning problem becomes a non linear, mixed integer optimisation, and development and application of other optimisation techniques become necessary (Newham 2008). Dynamic programming has been one of the most widely used optimisation techniques for the planning problem but this suffers from the ‘curse of dimensionality’. The overwhelming state space resulting from real world problems has required development of heuristics such as tunnel based constraints that allow the user to specify particular allowable states. Other heuristic techniques aim to reduce the state space by reducing the number of scenarios studied or restricting the investments available (Newham 2008).

Other optimisation techniques such as genetic algorithms, stochastic optimisation, decision analysis, trade-off analysis and artificial intelligence have been applied to various power system investment planning problems. Regardless of the type of optimisation technique used within the investment planning process, all rely on the characteristics of a regulated system such as transparency of information, financial certainty and industry co-operation. The introduction of deregulated or restructured markets has removed much of the certainty of power system investment planning and the tools used for planning and optimisation are no longer as relevant in their current forms (Newham 2008).

3.4 Generation planning after ESI restructuring

ESI restructuring introduces additional investment risks for generation expansion. The new risks introduced depend on the new structure implemented. As shown in Table 2.4, the wholesale market and retail competition structure places higher risks onto generation companies. Their business risks include (International Energy Agency 2003):

a) Economy-wide factors that affect the demand for electricity or the availability of labour and capital.
b) Factors under the control of the policy-makers, such as regulatory (economic and non-economic) and political risks, with possible implications for costs, financing conditions and on earnings.
c) Factors under the control of the company, such as the size and diversity of its investment programme, the choice and diversity of generation technologies, control of costs during construction and operation.
d) The price and volume risks in the electricity market.
e) Fuel price and fuel availability risks.
f) Financial risks arising from the financing of investment.

The degree of uncertainties that exist within the monopolistic market and the competitive market are summarised in Table 3.3.

Table 3.3: Change with respect to uncertainty as utility companies are restructured (Dyner and Larsen 2001)

Planning input	Uncertainty in key planning input	
	Monopolistic market	Competitive market
Price	Low	Medium/high
Information	Low	High
Demand	Medium	High
Consumer choice	Low	Medium/high
Regulation	Low	High

Under a competitive market, prices fluctuate, not only during the day and week but also depending on the season and weather conditions (e.g. summer/winter, amount of rain, etc.). Information becomes limited as no company would like to provide information to competitors. Demand forecasting becomes more difficult because the demand is no longer simply a growth or decline in the trend, but will depend more on the reliability and service provided as well as the price and marketing. With more competition in place, consumer choice is increased. Most governments encourage consumers to switch electricity suppliers regularly by providing simple switch over platforms (e.g. Powerswitch in New Zealand). ESI restructuring also took years to complete and there are many regulations that are set up from time to time, making it difficult for companies to plan many years ahead.

As the level of uncertainty increases, optimisation and hard modelling approaches need to be complemented with other planning methods such as behavioural simulation, financially based methods and scenario analysis. Dyner and Larsen suggested the planning and strategy methods for different decision making level as shown in Table 3.4 (Dyner and Larsen 2001). The methods are summarised in Table 3.5. Chapter 4 follows up on the methods that have been considered for this study.

Table 3.4: Planning and strategy methods according to the decision making level (Dyner and Larsen 2001)

ESI structure	Strategic (Long term)	Tactical (Medium term)	Operational (short term)
Monopoly	Hard modelling	Hard modelling	Hard modelling
Competitive markets	Hard modelling, strategic simulations, scenarios	Hard modelling, strategic simulations	Hard modelling, gaming

Table 3.5: Common planning methods used in the ESI after restructuring (Dyner and Larsen 2001; Newham 2008)

Method	Descriptions
Agent modelling	Provide understanding on the interdependencies in a system where individual actors in the industry can be represented and modelled in a variety of ways. Typically used to determine the optimal bidding strategy into a spot market
System/Business dynamics	Provide understanding on the interdependencies in a system based on explicit recognition of feedback and time lags on an aggregated approach
Competitive analysis/traditional strategy analysis	Allow companies to perform internally focused analysis such as their operations, staffing costs, competencies and capabilities and decide what they should outsource, (e.g. billing, meter reading etc.)
Financial risk modeling	Provide understanding on the risk related to contracting: what level of contracting and what kind of contracts should the company engage in to match a particular risk profile
Financial modeling	Provide understanding on the finance function in the company, i.e. concern with what type of debt to engage, the treasury function, etc. in the company
Game theory	To determine the best bidding strategy, it is necessary to take into account what the others might bid, given their constraints and objectives
Real options	Provide a framework for identifying the optimal investment time. Useful when there is an environment with a high degree of irreversibility and uncertainty.
Scenarios	A planning, strategy and communication tool by companies as a way of thinking about the long-term future where the degree of uncertainty is too large

3.5 Market interaction with generation investment

This section presents a theoretical model that describes how the power market can determine generation investment, extracted from Leveque 2006 (Lévêque 2006). This model considers two types of generation capacity: peaking and base load. Figure 3.2(1) shows the marginal costs of the two types of plants. Peaking plants have relatively low fixed costs (intercept with y-axis) but relatively high marginal costs per energy generated (steeper slopes). In contrast, base load plants have higher fixed costs but lower marginal costs per MWh.

The total annual costs in operating the plants depend upon the number of hours per year for which the plant is operated. If the station is required to run for T* hours or less per year, then it is cheaper to run a peaking plant. But if it is required to run for more than T* hours, then base load plants have lower total costs. The bold line in Figure 3.2(1) gives the lower envelope of the two linear total cost functions, showing the efficient cost of meeting a demand lasting for any given number of hours.

Figure 3.2(2) shows the load duration curve (LDC) where the hours of the year are ranked in order of the demand for electricity, so that the hour with the highest demand is placed at the right hand end. The vertical axis then shows the demand in that particular hour. The demand during the T*th highest hour is thus B GW. This is the gross demand for electricity, including transmission losses and the amount of plant that has to be kept part loaded or available at short notice, for reserve. In other words, there are T* hours in which this gross demand for electricity is B GW or more. This implies that if it is wanted that base load plants meet all the demands for electricity that last for T* hours or more of the year, then it should be ensured that B GW are available.

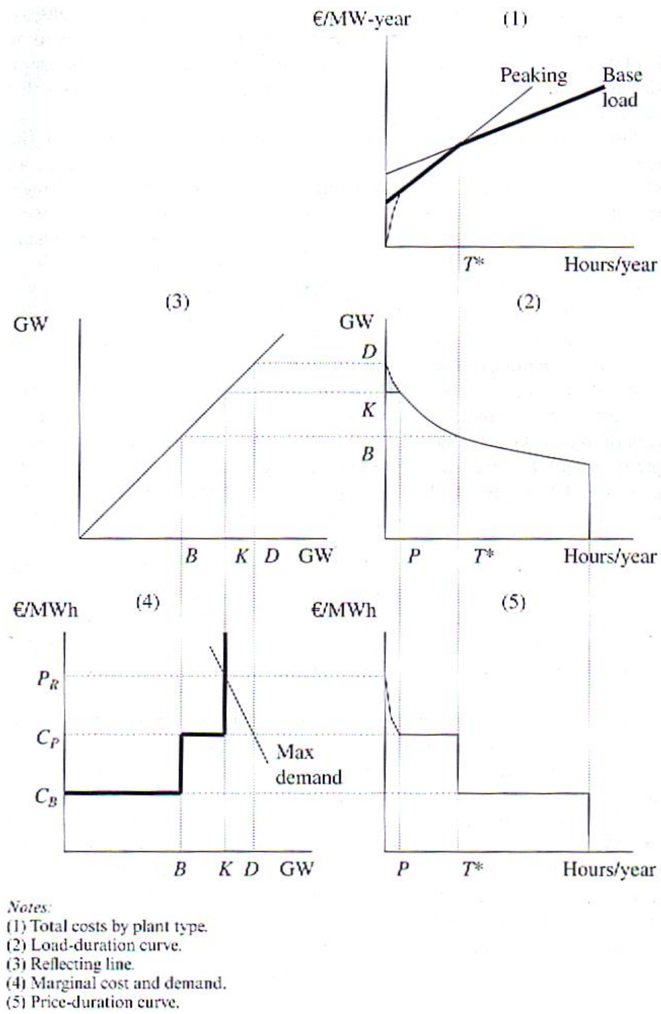


Figure 3.2: The determination of electricity capacity and prices (Lévêque 2006)
Legend:
C_P = marginal cost of peaking plants; C_B = marginal cost of base load plants

In the traditional ESI structure, information on T* and B are sufficient for regulators to set the electricity prices and ensure that the ESI was able to recover its average costs. In a wholesale market structure, it is assumed that under perfect competition, bidders will set prices to be equal to marginal costs.

Figure 3.2(3) is a reflector used to move the capacities shown in the vertical axes of Figure 3.2(2) to the horizontal axis of panel 4. If the marginal (operating cost) of base load plant is equal to C_B, then C_B will be the marginal cost of the industry whenever demand is equal or less than the capacity of this type of plant – assumed to be B GW at the optimal solution. At times of higher demands, the marginal cost will equal C_P, the marginal cost of peaking plants.

In terms of total capacity, Figure 3.2(2) has been drawn on the assumption that the price in the first T* hours of the year is equal to C_P and that the price for the rest of the year is C_B. At the price of C_P, the maximum demand for electricity is equal to D GW. If the industry had this much capacity, then that demand could be met in full, but the price would never exceed the marginal cost of the peaking plants, C_P.

The slope of a total revenue line (per MW per year) for a peaking plant is identical to the slope of the total cost line for peaking plants over the period between P and T* hours. Hence the total annual revenue for a peaking plant per MW, R_P is equal to

$$R_P = C_P*(T^*-P)$$

Base load plants are generally used throughout the year, less the hours of planned or unplanned outages, and hence their total annual revenue per MW is

$$R_B = C_B*(8760\text{-hours of outages})$$

From these equations, it can be deduced that base load plants make a contribution towards their fixed costs since the price exceeds their variable costs for the first T* hours of the year. On the other hand, if the market price never exceeds C_P, peaking plants would not be able to cover their fixed costs. This is clearly not sustainable in a market which investors are free to leave, and will not enter without a clear expectation that they will cover their costs, including an appropriate return on capital. The inadequacy of the market to encourage investments on peaking plants provides an excuse for generation companies to exercise their market power at the time of high demands to recover their peaking plants fixed costs. The next sections consider several possible scenarios for the electricity market.

3.5.1 Scenario 1: Capacity not sufficient to meet demand

When total generation supply capacity is unable to meet the demand D GW in full, the system operator (SO) may be able to reduce the amount of reserve plant that it is carrying so that customers are not immediately affected, although this increases the risk of failures disrupting supply to larger numbers of customers. The cost of such as failure, multiplied by its probability, gives the value of additional generation at these times. With a shortage of capacity, generation companies are able to exercise their market power and bid up to this expected cost, and it would be rational for the SO to pay it, even when it is greater than the generator's marginal operating cost. It is also possible for the SO to ask for load management, and can start to pay some customers to reduce their demand. Bids from these customers might set the price in a real time market directly, or generation companies might raise their bids above their marginal cost, knowing that their competition now comes not from one another (since all generation plants are needed) but from the demand side.

This is demonstrated in Figure 3.2(4) where the downward sloping line represents the maximum demand. If there were D GW of capacity available, the price would be C_P. However, with less capacity, the price must rise to clear the market. If there is only K GW of capacity available, then the price will rise to P_R to ration demand to the level of the capacity. P_R can be set by either the variable operating costs of the last plant available, the bid set by the generation company who wishes to exercise its market power, or the opportunity cost of a consumer that has decided to reduce its demand.

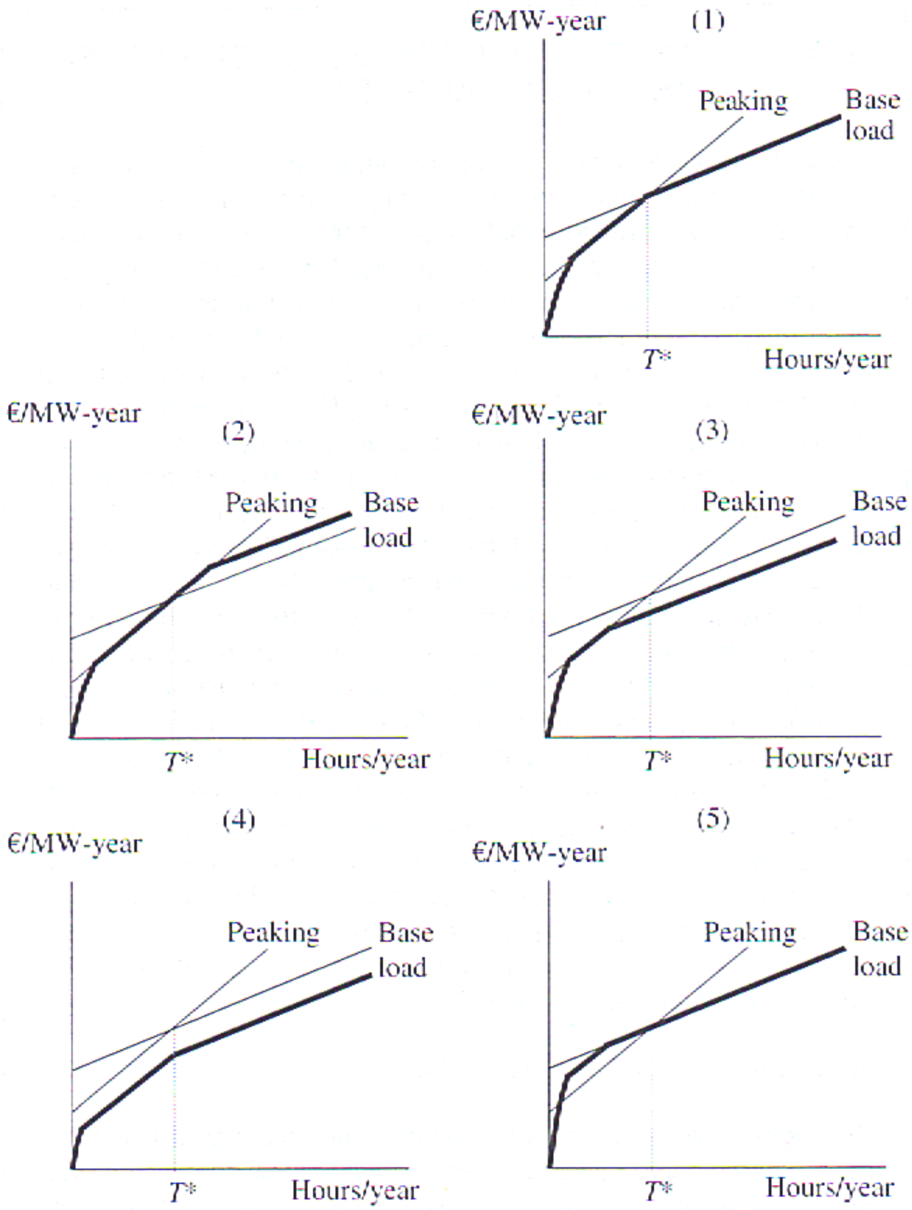
Figure 3.2(5) shows the price duration curve. At the highest demand hour, the price must clear at P_R but lower prices are possible in hours with lower demands. After P hours, the LDC of Figure 3.2(2) shows that the demand at a price of C_P has fallen to K GW and can be met in full by the supply capacity. In terms of load actually served, the LDC thus has a flat segment at K GW; the area above represents 'unserved' load due to the supply shortage. Between P and T* hour, the price in a perfectly competitive market is equal to C_P. But from T* onwards, none of the peaking plant is needed, so the marginal cost falls to C_B.

3.5.2 Scenario 2: Wrong mix of generation capacity

The previous model and scenario discusses the scenario of an optimal mix of peaking and base-load generation capacity. This is shown again in Figure 3.3(1). The other panels in Figure 3.3 show other possible combinations of generation mix. As discussed in the previous section, if there is too little total generation capacity, peaking plants can make a supernormal profit. On the other hand, if there is too much total capacity, they will make losses. If there is too much base load capacity, then base-load stations will make less profit per MW-year because the market clearing price can be set lower than the base-load marginal price. If the base load is too little, then the market clearing price can be set higher, and peaking plants will need to run more often, causing the average wholesale electricity price to increase.

3.5.3 Scenario 3: Wrong level and mix of generation capacity

Figure 3.3(5) shows a scenario when the total generation capacity is too large compared to demand and there is too much base load capacity. In this case, a shortage of total capacity means that prices exceed C_P for more than P hours, making the total revenue line move above the total cost line for peaking plants. It then runs parallel to that line for some hours, until demand falls to the level of base load capacity and those plants become marginal. This can cause all the base load plants into losses, because prices would be set at C_B longer than they should be.



Notes:
(1) Optimal capacity mix.
(2) Right total, too little base load.
(3) Right total, too much base load.
(4) Total too large, right base load.
(5) Total too small, too much base load.

Figure 3.3: The impact of capacity mix on wholesale prices

3.6 Impacts of restructuring on generation investment

In Section 2.1.2, it was mentioned that investments under a regulated ESI were perceived to be inefficient because even a bad investment is guaranteed to be profitable. Hence, one of the functions of the restructured market is to stimulate suitable generation investments at the correct time, i.e. providing adequate and correct mix of supply, in time to meet the growing demand.

In principle, deregulation dictates that decisions on generation investments are left to market participants, based on commercial principles. Capacity expansions are thus driven by expectations of future prices and return on new investments (Doorman and Botterud 2008). Some systems are mainly based on these market principles, e.g. present UK model, the Australian market, Nord Pool and the New Zealand Energy Market (NZEM). Generation investment under this market principle is solely based on the wholesale electricity market price. A high price that is sustained for a certain long duration indicates that the margin between the electricity supply and demand is small and there is a need for new generation investment to meet the demand. Any generation company that feels that they can gain profit by constructing a new plant will then proceed to develop it.

In the past, with regulated planning, the generation capacity is maintained at a certain level to ensure that the supply can meet demand at all times. Even though this was interpreted as over investment and inefficient, no blackouts or crises occurred due to supply shortage. On the other hand, in a deregulated market, it is difficult to maintain an adequate level of generation capacity (Doorman and Botterud 2008). This has caused boom and bust cycles in generation capacity in many places such as the US, Europe and New Zealand, as discussed by several publications (Ford 1999; Kadoya, Sasaki et al. 2005; Lévêque 2006).

3.6.1 Generation capacity trends in some countries

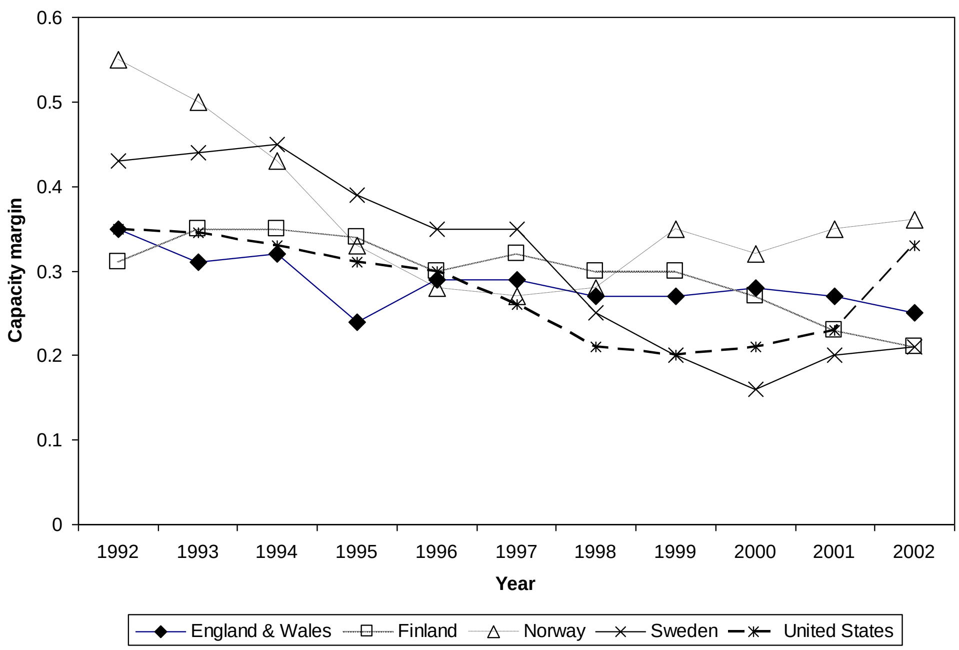


Figure 3.4: Capacity margins in several countries after they deregulated their ESI (Lévêque 2006)

Figure 3.4 shows the capacity margins in England and Wales, Finland, Norway, Sweden and the United States after they deregulated their ESI in the early 1990s (Lévêque 2006). The figure was summarised from the study done by Richard Green and published in the book "Competitive Electricity Markets and Sustainability" (Lévêque 2006). The original figures from the analysis are included in Appendix A. The capacity margin is defined as the excess of generation capacity over peak demand, as a proportion of that peak demand. The next paragraphs discuss the situations that caused the change in capacity margins in the countries shown in Figure 3.4.

In England and Wales, prior to their ESI restructuring in 1990, the generation capacity margin was more than 30%, above the planning margin of 28% used by the national Central Electricity Generating Board. After restructuring, many plants were closed down by major generation companies, making way for new entrants and keeping plant margins from rising (Lévêque 2006). Hence, capacity margins declined steadily through the 1990s.

As for the U.S., Figure 3.4 shows only the nationwide averages. The trends in individual regions may vary. In particular, low capacity margins in the western states contributed to the California crisis of 2000-01. On a national scale, capacity margins were high in the early 1990s. Low investment took place in those years causing the margin to fall with increased demand. The investment delay was due to uncertainties introduced by the restructuring causing most investors to wait until policy was decided. Investments took place around 1998 with new capacity of over 20% added between 1999 and 2002, well beyond the optimal level of investment. This is an example of a bust period followed by a boom period in generation capacity after deregulation.

In Norway, the capacity margin fell sharply in the first half of the 1990s, after liberalisation in 1991. Very little investment took place. However in 1997, the capacity margin rose, but due to lower peak demands rather than an increase in the generation capacity. As a hydro dominated system, Norway will always require a relatively high margin of generation capacity over peak demand, because the average hydro plants there can only store enough water to operate for about half the year. Over the 1990s, Norway had made up for a decline in its capacity margins by importing increasing amounts of power in dry years (Lévêque 2006).

Finland liberalised its market in 1996. There have been very few plant closures since then. There was a significant amount of investment in the years immediately after liberalisation (which will have been planned before liberalisation took effect). Very few new plants have been commissioned since then, resulting in a decline in the capacity margin. However, more plants are needed as demand grows and old power plants retired. Work started in spring 2005 to build a 1600MW nuclear reactor (Lévêque 2006).

In Sweden, capacity margins were high at the start of the 1990s. The country has a mix of hydro and thermal resources, so the appropriate margin will be lower than for Norway. After the liberalisation in 1996, Sweden's capacity margin fell when many old plants were retired. The Swedish system operator, Svenska Kraftnät, was concerned with the low margins and paid plants to be brought back into service as capacity reserve after mothballing in 1998 and 1999 (Lévêque 2006). These reinstated plants accounted for nearly 75% of the capacity added between 2001 and 2003.

As for New Zealand, the generation capacity is also affected by its ESI restructuring at around the mid 1980s. Figure 3.5 shows that the installed generation capacity fell for the first time in 1988. This can be most probably attributed to the uncertainties introduced when the government was considering ESI privatisation and restructuring during those years.

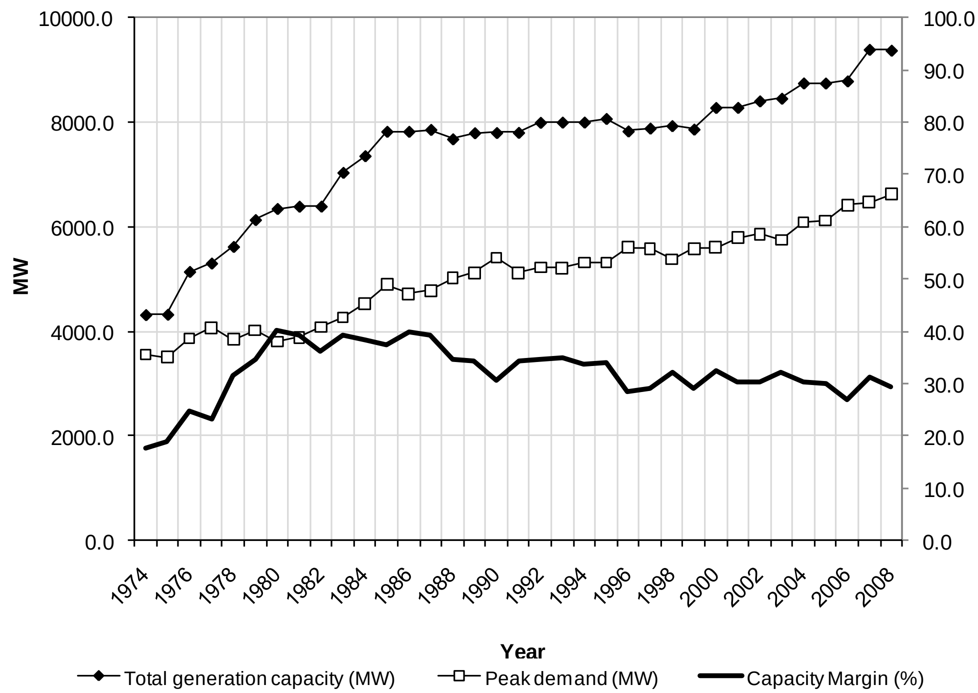


Figure 3.5: A plot of installed generation capacity, peak demand and capacity margin in New Zealand from 1974 to 2008

The installed capacity was on a plateau for over a decade, causing the margin between the supply and demand to become smaller within those years and reducing the capacity margin. The installed generation capacity increased after 2000 and rose steadily with increasing demand. Despite the reduced capacity margin, New Zealand did not have any problem meeting peak demands. It did, however, have a problem meeting energy demand during dry winter years due to the reduced hydro inflows. This problem can be analysed further by calculating and plotting the energy capacity margin (ECM) as shown in Figure 3.6. Energy capacity margin is a measure of excess energy generation capacity per energy consumption. The calculation of the ECM is discussed in Chapter 6. A low ECM indicates the possibility of an energy constraint where there is not enough electric energy generated to meet demand. The maximum annual electricity generation in Figure 3.6 is the product of the total annual generation capacities with their typical operating hours.

Since 1988, four shortages have been observed. The first power crisis occurred in 1992 when the ESI was privatised and operated under the Electricity Corporation on New Zealand (ECNZ). Three more shortages were observed in the winters of 2001, 2003 and 2008 after the New Zealand Energy Market (NZEM) commenced operation in October 1996 (Ministry of Economic Development New Zealand 2009)

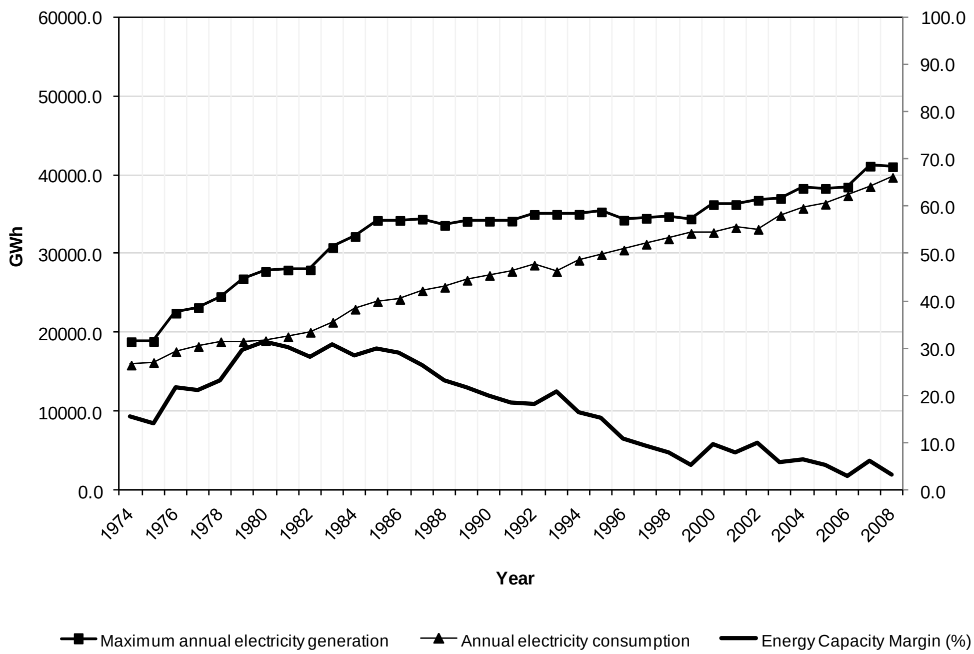


Figure 3.6: A plot of generation capacity and electricity consumption trends in New Zealand from 1974 to 2008

Comparing the trends in these countries, it can be observed that liberalisation has often been accompanied by a reduction in capacity margins. But this was not necessarily to a level that posed a danger to the security of supply even though some places like California and New Zealand were affected by the low generation levels. When capacity margins become very low, investments follow. However, due to the uncertainties of profit returns with changing wholesale electricity prices, investors wait for the time they deem would give them most profits.

3.6.2 Reasons for investment cycles in a market driven industry

In reality, many market driven capital intensive industries are prone to investment cycles. This has been observed in many industries such as real estates and copper industries (Ford 1999; Lévêque 2006; Sterman 2000). The electricity industry is also vulnerable to similar problems.

At first, the industry may be short of capacity and prices will be high. This acts as a signal to investors to start adding capacity. In the absence of coordination, they are in danger of over-reacting. Too many investors read the high prices as a signal that their own investment will be profitable and somehow fail to take their competitors' actions into account. Once the new capacity comes on stream, it will depress prices. This will be sufficient to halt most new investments but the existing capacity is likely to stay in service. Scrapping decisions are irreversible and will not be taken unless the price falls sufficiently below the variable costs of staying in operation. Eventually, the energy capacity margin will fall as plants are retired or demand rises, pushing the prices up again to the point where investment is again perceived as profitable. The industry is then in danger of repeating the cycle (Lévêque 2006).

3.6.3 The impacts of generation capacity cycles

The generation capacity cycles make it difficult to predict whether a country will have enough electricity supply to meet demand. Extra capacities can be deemed as inefficient stranded investments, but on the other hand, capacity shortages are not easily addressed as power plants take years to be developed. When a country faces an electricity shortage and undergoes curtailments, it means that some productivity opportunities are lost. If the condition is prolonged, millions of dollars can be lost and social and political problems might arise.

In some countries, the authorities were not comfortable with leaving the decisions on generation investment completely to the market and introduced several policies to support the market structure. Such policies are capacity payment systems (as in Spain and South America), capacity obligation systems (US), capacity adequacy system based on reliability options (theoretical) and capacity subscription (Botterud 2003). However, the effectiveness of these systems has yet to be proven. Wolak claimed that capacity payment systems can lead to over investments and higher electricity prices. They also do not address the problems of market power abuse (Wolak 2001).

3.7 Chapter summary

Theoretically, generation planning consisted of developing and having a portfolio of generation facilities available to meet the various types of electricity loads that occurred in any given hour, across any given day, in any given season. Under the traditional monopoly market model, reliability tended to be the most important planning consideration, followed closely by cost. Thus, generation planning strategies consisted of constructing and operating enough power plants to meet demand. Regulators were responsible to ensure supply reliability.

Under a deregulated market structure, energy security is no longer the driver for generation investments. Investments are driven solely by revenues and this has introduced boom and bust cycles in generation capacities. Boom periods can cause inefficient stranded investments whereas bust periods can cause supply shortages that may take years to fix.

4 RESEARCH METHOD: SYSTEM DYNAMICS

The various optimisation techniques to plan regulated power systems were discussed in Chapter 3. However, due to the linear nature of the method, it cannot be used to study boom and bust cycles. This research uses a System Dynamics (SD) method to analyse the impact of the market structure on generation expansion. The first section of this chapter provides a brief description of this method. It then briefly discusses two other methods that are used to study similar problems. Section 4.3 then describes the advantages of the SD method. The chapter concludes by mentioning other publications and research on ESI using SD.

4.1 SD descriptions

SD is a descriptive modelling method based on explicit recognition of feedback and time lags (Forrester 1961; Sterman 2000). It is a type of behavioural simulation modelling. It was created during the mid 1950s by Professor Jay Forrester of the Massachusetts Institute of Technology. Initially it was applied almost exclusively to corporate/managerial problems. After the late 1960s, its application started to expand into other fields such as energy, ecology, social studies and economics. Rather than applying the method to study one system, it can also be used to study the interactions between different multidisciplinary systems.

4.2 Other methods used to study electricity market interaction with generation expansion

Among all the methods mentioned in Table 3.5, the two other methods besides SD that are applied to study the interaction between the electricity market and generation investment are game theory and real options theory. As mentioned in Section **Error! Reference source not found.**, with a restructured ESI, additional risks and factors have to be taken into consideration before making an investment decision, such as uncertainties in the market environment and competition from other investors.

4.2.1 Real options theory

Real options theory has been used to analyse the uncertainty and timing of individual generation investments in power systems. The theory originated in finance and is used to assess the value of deferring investment that is subject to uncertainty. It assesses the additional value in waiting for uncertainty to reveal itself so that the investor can delay making an irreversible investment. An uncertainty is described as a stochastic process. In other words, real options create a shift from the traditional ‘‘fear of uncertainty’’ to a view of ‘‘seeking gains from uncertainty’’(Dyner and Larsen 2001). Some examples of studies which used real options theory to study generation investments are listed in Table 4.1.

Table 4. 1: Examples of research using real options to study generation investment

Researchers	Research objectives	Result
Smit and Ankum (Smit and Ankum 1993)	Studied the value of investment deferral using real options under the different competitive scenarios of perfect competition, oligopoly and monopoly	Under perfect competition, there is a tendency to invest early to avoid the erosion of investment value by competitive investment. In a monopoly, there is no loss of value due to postponement so there is tendency to delay projects. Oligopoly lies between competition and a monopoly where cooperation between investors tends to delay investment but as soon as one makes an investment, the others will follow immediately.
Keppo and Hao (Keppo and Lu 2003)	Studied the effect of large investments on future prices	Showed that production's price effect has to be considered in the investment analysis if the company is not able to hedge the price effect in the financial markets.
Botterud et al. (Botterud, Ilic et al. 2005)	▪ Studied optimal investment decisions when demand growth and hence future prices are uncertain. ▪ Used an explicit power market model that utilises linear supply and demand curves to calculate the electricity price. ▪ Studied investments in both restructured and regulated environments and identifies the option value of delaying investment.	Showed how price caps and price feedback can affect the timing of investment decisions.
Marreco and Carpio (Marreco and Carpio 2006)	Studied the optimum value for capacity payments to incentivise generation investment and availability	Concluded that a financial subsidy is mandatory for the economic feasibility and increased thermo power capacity in the Brazilian Power System. Their model was able to solve for the flexibility value as a fair premium incentive to investments.
Botterud and Korpas (Botterud and Korpås 2007)	Investigated how fixed or variable capacity payments affect investment decisions in the Norwegian power market.	Capacity payments can induce earlier investments but that the kind of payment, i.e. fixed or variable, affects the timing of investment decisions.

Real options theory is a useful and promising technique for an individual investor to assess the value of an investment and the value of deferring an investment. It is best suited for use by individual investors to investigate investment choices and timing under uncertainty. It does not help with coordination of investment planning throughout the power system as each real option analysis considers a single investment option and fixed location.

4.2.2 Game theory

One aspect that contributes to price volatility is competition between market participants. Competitive behaviour affects both short term prices, where generation companies compete in the real time spot market, and long term prices, where generation investors can influence the long term electricity price by the size, type and timing of new investments. Competition causes investors to face higher risks and therefore seek higher returns. It also results in investment decisions affecting other investors' profits and decisions. The interaction, competition and resulting outcomes for deregulated power markets have been studied using game theory. Some examples of studies which used game theory to study generation investments are listed in Table 4.2.

Smit and Ankum (Smit and Ankum 1993) use a combination of real options and game theory to study the interactions between competitive investors when uncertainty is considered. Previous work has shown that competition may force an investor to invest early and therefore the option value in deferring the investment is lost. Smit and Ankum consider the reduction in investment value for differing scenarios of market power of investors. They show that in an oligopoly it may be beneficial for all investors to defer investment if the project value is low and demand is uncertain. In contrast, in a very competitive environment, firms are likely to invest immediately in order to preempt an investment by another party. This can result in a suboptimal solution.

Game theory has been used to study a range of competition issues in power systems. A number of the studies undertaken offer promise in terms of identifying potential behaviour of rival investors, but only Smit and Ankum consider uncertainty within the model. The use of game theory in power system planning would seem to be in identifying specific actions by investors at a potential point in time but it is less suited to a system wide planning perspective. One aspect of game theory that has not been discussed is the assumption that all players, or investors, act rationally. Rational actions in this context relates to an investment being made on a financial basis where an investment decision is based purely on profit. While profit and income is a driving factor for investment, other factors also likely to make an impact are things such as work force requirements, company vision and the political environment. Hence, investors cannot be merely considered as acting rationally and as a result, the outcome predicted by game theory may not eventuate (Newham 2008). Another difficulty in using the model is that finding a Cournot equilibrium[1], if one exists, becomes progressively more difficult for more detailed models.

[1] Cournot's theory, firms choose how much output to produce to maximize their own profit. However, the best output for one firm depends on the outputs of others. A Cournot equilibrium occurs when each firm's output maximizes its profits given the output of the other firms.

Table 4.2: Examples of research using real options to study generation investment (Newham 2008)

Researchers	Research objectives	Result
Kleindorfer et al. (Kleindorfer, Wu et al. 2001)	Studied the strategic gaming interactions of market participants during real time operation and dispatch and ancillary services contracting.	Developed a model termed Electric Power Strategy Simulation Model (EPSIM) that can be used by market participants to test strategic plans before implementation.
Chuang et al. (Chuang, Wu et al. 2001)	Used Cournot theory to model generation expansion in a competitive electricity market. A Cournot equilibrium is reached when an investor cannot better their financial position by changing their investment decision, with respect to their competitors' investment decisions.	Their numerical results pointed to greater industry expansion and system reliability under Cournot competition than under centralized expansion planning; and higher probabilistic measures of reliability from multi-player expansion than from expansion by a traditional monopolist with an equivalent reserve margin requirement.
Diego (Diego 2002)	Studied the use of non cooperative game theory to analyse the economic behaviour of generating companies with respect to the real time power pool market.	A model which can be used to investigate the market rules and their impacts on incentives and the following actions of generation companies.
Murphy and Smeers (Murphy and Smeers 2005)	Studied three different generation investment models- traditional expansion planning, oligopolistic market environment where capacity is simultaneously built and sold in long-term contracts where there is no spot market (similar to power purchase agreements) and a spot market where investment and sales are separated.	Prices and quantities produced in a spot market fall between the traditional planning model and the oligopolistic model. This is a result of the spot market mitigating market power with the resultant price being lower than that of the oligopolistic model.

4.3 SD advantages

Due to the disadvantages of the methods described in Section 4.2, they have not been used in this study. On the other hand, there are advantages offered by the SD method that makes it suitable for this study. A behavioural type of simulation such as SD can provide an understanding of how competitors behave and how the market might move, as it is unlikely that it will follow an economically rational path (Dyner and Larsen 2001). What makes SD different from other methods is that it utilises feedback loops, stocks and flows which helps in studying nonlinearity in a system. Traditional simulation models have tried to include as much detail as possible, and thereby generate better predictions. SD models, on the other hand, have increasingly focused on understanding the dynamic path into the future. The focus has been on learning: facilitating a better understanding of how the industry (or the system generally) evolves over time, understanding which variables are critical and where to intervene in the system to create a desirable outcome (Lomi and Larsen 1999).

One further advantage of using the SD method is that the framework can be tested at a very early stage of restructuring, where most other methods do not work because there is little if any data. A good understanding of how the regulatory framework will play out can still be obtained (Larsen and Bunn 1999; Lomi and Larsen 1999).

4.4 Past work using SD to study the ESI

The earliest significant application of SD models was for the energy sector in the U.S since the 1970s (Backus 2009). Initially, the Federal Energy Administration used Project Independence Evaluation System (PIES) for policy evaluation. The successor to the PIES model was then supplemented by a policy oriented model based on SD called FOSSIL1 because:

- It allowed faster computation (12 seconds versus 100 hours)
- It allowed policy analysts to easily explore various options before presenting them
- The SD method provided a casual explanation understandable to policy makers

- It allowed exploration of various policy considerations and turn them into passable legislation. It is believed that FOSSIL1's ability to reveal the varied, shifting impacts of energy policy over time played a large part in achieving national oil and gas deregulation legislation.

Under the championship of Roger Naill, FOSSIL1 morphed into FOSSIL2 and was used from 1978 through to beyond 1995 as the U.S. National Energy Policy Model by most U.S. and international energy analysts. Even though FOSSIL2 was later taken over by another model called National Energy Modelling Systems (NEMS), it was further advanced by George Backus into another SD model called ENERGY2020. SD applications in energy modelling have been widely published (Naill 1992; Naill, Belanger et al. 1992; Dyner 2000; Backus 2009; Chin-Yen, Burns et al. 2009).

Applications of SD models specific to the ESI started in 1983 when the Economics Group at the Los Alamos National Laboratory, U.S. developed an SD model called Electric Utility Policy and Planning Model (EPPAM) to study the spiral of impossibility in the electric utility industry prior to the ESI restructuring (Ford and Youngblood 1983). The spiral of impossibility happens because of the long lead time of power plants' construction. Before construction, the utility company raises the price of electricity to fund the construction. The higher price dampens demand growth, making the consumption less than what has been initially forecasted by the utility. This makes the built capacity more than the required consumption, causing a shortfall of revenues. When the utility raises the price further to cover the fixed cost of the plants, the demand growth is dampened further and the utility faces what is known as the "spiral of impossibility". Their study showed that the spiral can pose substantial planning problems for utility companies with long lead time power plants and serving customers that react strongly and quickly to changes in the price of electricity.

The best policy in minimizing the spiral's effects is to shift to generating technologies with shorter construction lead times.

In 1992, Bunn and Larsen used SD to study the impact of ESI restructuring in the U.K (Bunn and Larsen 1992). Their study examined the effectiveness of the 1992 pool market mechanism in stimulating investment in electricity generating capacity. Their work showed that if generation companies responded simply to the capacity element as generated by the daily market for electricity, then severe cycles of under and over capacity would result. In 1999, they performed an evaluation of their 1992 paper and showed that the broad insight from the early study had in fact been correct, whereby the problems raised in the study had been seen in the industry during the 1990s (Larsen and Bunn 1999).

In 2001, Andrew Ford applied SD to study the California electricity crisis (Ford 2001). His study showed that the American western ESI were prone to boom and bust cycles that appear in commodity markets. Without fundamental changes in the wholesale market structure, their next construction boom would come too late to prevent a decline in reserve margins and the reappearance of price spikes as happened in 2000 and 2001. He suggested that wholesale markets could be improved if private investors receive an additional incentive in the form of fixed capacity payment. Ford has also used SD to analyse various issues in the ESI such as:

- Effects of energy conservation practices on utility performance (Ford, Bull et al. 1987; Ford and Bull 1989)
- Impact of efficiency standards on utility planning (Ford and Geinzer 1990)
- Impacts of electric vehicles on utilities (Ford 1994)

In his recent studies of the ESI, Ford has also combined SD models with other approaches such as the engineering approach (Dimitrovski, Ford et al. 2007).

In 2005, Kadoya et al (Kadoya, Sasaki et al. 2005), used SD model to study the long term stability of the deregulated industry. They modeled two power producing regions in the U.S. - Pennsylvania-New Jersey-Maryland Interconnection (PJM) and the Independent System Operator – New England (ISO-NE) and validated the models against 20 years of data. Applying Monte Carlo analyses to their models suggested that for a realistic range of assumptions, deregulated wholesale power markets are substantially more cyclical than they would have been under a regulated monopoly regime.

Two studies that utilized SD to model electricity systems for hydro dominated countries are Olsina's (Olsina 2005) on Argentina's power system and Vogstad (Vogstad 2004) and Botterud (Botterud 2003) on the Nordic electricity market. SD has also been used to test new market mechanisms in a restructured ESI. Some examples on this kind of work are:

- Development of improved mechanism for capacity payment (Hobbs 1995; Hobbs, Hu et al. 2007; Assili, Javidi D.B et al. 2008)
- Analyses on alternative regulations in the Colombian electricity market (Arango, Smith et al. 2002)

SD has also been used to provide some insights on how the ESI in developing countries could be impacted after they are restructured. In 2006, Kiani et al. (Kiani, Jadid et al. 2006) used SD to examine the impact of ESI restructuring on generation capacity growth in Iran. In 2009, Balnac et al. used SD to study privatisation policy impacts onto the ESI in Mauritius.

4.5 Chapter summary

Real options and game theories are capable of being used to study some aspects of generation investments. However, for this study, SD methods have been chosen to fulfil the research objectives.

5 ELECTRICITY SUPPLY INDUSTRY IN NEW ZEALAND

This chapter provides a background of the ESI in NZ with emphasis on restructuring. The current New Zealand market structure, the problems faced and the past energy shortages are elaborated on. The chapter then focuses on the generation expansion issues in New Zealand. Planning methods and relevant national policies that impact the sector are then discussed.

5.1 Geography of New Zealand

New Zealand is a country in the south-west Pacific Ocean, lying between latitudes 33º and 48º South and longitudes 165º and 179º East. Its land covers an area of 268,680 square kilometres. Most of its land mass is made up of two islands – the North Island and the South Island – but there are also a number of smaller islands. Its capital is Wellington, situated at the southern end of the North Island.

Its latitudes pass through the temperate zone of the world, but the climate is influenced by the surrounding sea. The weather of any particular area varies due to its mountainous terrain in certain regions. With a total population of about 4 million people, New Zealand has a low population density. About 80% of the population lives in cities, particularly in the North Island cities of Auckland and Wellington. New Zealand has abundant natural energy resources of coal, natural gas and hydro, though current natural gas fields are rapidly declining (International Energy Agency 2006).

5.2 Early history of electricity usage in New Zealand

The first recorded use of electricity in New Zealand was in 1861 for a private telegraph line between Dunedin and Port Chalmers. In 1863, the first government lines installed by a provincial council connected Christchurch to the port of Lyttelton. The first substantial use of electricity for the public was for lighting. After several private lighting installations, various electrical companies came into the picture in 1882 (Martin 1998). The first major hydroelectric generation of power in New Zealand was in 1886, powering the Bullendale gold mine in Otago. Following that, in 1888, a company, Reefton Electrical Transmission of Power and Lighting, was formed with 65 shareholders. Electricity was offered for sale to the public there for the first time from sunset to sunrise (Martin 1998).

5.3 Initial roles of the government

During the early development stage of electricity in New Zealand, the government's role was to only regulate the electricity supply. The initial physical infrastructures were mainly set up by private companies. In 1865, the Electric Telegraphic Act established a central government monopoly over the transmission of messages and provided for state construction, maintenance and regulation of telegraphic telecommunication (Martin 1998). The act was consolidated in 1875 and then incorporated in the Electric Lines Act 1884 to extend the coverage of government legislation to electric lighting of public places and to telephones. The Electric Lines Act ensured proper quality and care of the electric lines (Martin 1998).

The government then started to get involved in electric power generation. The Electrical Motive Power Act of 1896 emphasised that any generation or use of electricity for motive power should get permission from the central government rather than the local authorities. The Water-Power Act 1903 gave the government the sole right to use water for generating electricity. These two Acts were then incorporated into the Public Works Act 1908 (Martin 1998).

The Aid to Water-Power Works Act 1910 authorised the raising of ₤500,000 by the government for the construction of electric power works and use of water for power generation. In 1910, the Water-Power Works Account was established (later named Electric Supply Account). All loans raised for hydro electric schemes and income received from electricity sales went to this account. This provided the commercial basis for the government's bulk supply of electricity. The government's financial role was formalized in the State Supply of Electrical Energy Act 1917 (Martin 1998).

Lake Coleridge was the first major government hydroelectric project, constructed from 1911 to 1914 (Martin 1998). The success of this first scheme led to several large scale hydroelectric schemes, which have been in operation thereafter. This gave the concept of an integrated system of stations to provide power across the country.

In 1918, Evan Parry, the first Electrical Engineer in the Public Works Department, proposed the creation of a linked network of electricity with the aim of a fully integrated system with a standardized voltage supplying various people and needs. The Electric Power Board Act 1918 was passed with the aim of setting a pattern for the reticulation of electricity (Martin 1998). This formed the foundation for the transmission network in New Zealand.

The Municipal Corporations Act 1920 gave the municipalities the right to build power stations, distribute electricity and to transfer funds from their profitable electricity departments to other activities, actions which were prohibited by the previous Electric-Power Boards Act (Martin 1998). The new Act provided a faster track in giving the rural districts early access to electricity. All the distribution networks in New Zealand then came under the local municipals until they were privatised later.

5.4 Prior to Restructuring

By the mid-1980s, electricity generation and transmission were the responsibilities of a government department, the Ministry of Energy. This Ministry was also responsible for policy advice and regulatory functions. Regional electricity distribution and supply were the responsibility of sixty-one electricity supply authorities who were also the local municipalities. They were electorally selected and became the statutory monopolies in their respective regions (Ministry of Economic Development New Zealand 2009).

5.5 Factors for the ESI reforms

The ESI restructuring in New Zealand started in the mid 1980s (Ministry of Economic Development New Zealand 2009) for various reasons. In terms of electricity supply, there was extensive political involvement in generation investment decisions. Project management was said not to have met the correct standards. Wholesale pricing was claimed to have been determined by political factors. Since the electricity supply was done by the local government, there was no competition and the consumer did not have any choice. This was claimed to be inefficient (Ministry of Economic Development New Zealand 2009).

This set of circumstances coincided with increasing concern about New Zealand's overall economic performance. Outcomes sought included economic growth through efficient resource use, driven by clearer price signals, and, where possible, by competitive markets (Ministry of Economic Development New Zealand 2009). In the early 1980s, a major inter-departmental review of the Crown's role in the electricity industry was commenced, looking to separate operation from other functions, and to improve performance by introducing commercial disciplines for trading activities.

5.6 The transition to the present structure

The Electricity Amendment Act 1987 came into force on 1 January 1988, removing the need for the Minister of Energy to approve all new hydro generation proposals. The Ministry of Energy was then abolished, effective from December 1989. Its policy, regulatory and other non-commercial roles were transferred to the new Energy and Resources Division (now the Resources & Networks Branch) of the Ministry of Commerce (now the Ministry of Economic Development). A small number of residual and transitional Ministry of Energy commercial responsibilities were transferred to The Treasury (Ministry of Economic Development New Zealand 2009).

5.6.1 Electricity generation and transmission reforms - Electricity Corporation of New Zealand (ECNZ)

The Electricity Corporation of New Zealand (ECNZ) was formed on 1 April 1987 under the State-Owned Enterprises (SOE) Act, with the aim to commercialise the government's trading departments (Ministry of Economic Development New Zealand 2009). It owned and operated the electricity generation and transmission assets of the Ministry of Energy. Policy and regulatory activities were separated out and largely retained in the Ministry of Energy (prior to their abolishment). The expectation of the new corporation was that it would perform more efficiently while investing prudently, and that it would lead the way in the economic reforms.

The SOE Act was a component of the Government's moves to improve the performance and accountability of the public sector. SOEs are companies in which nominated Ministers hold all the shares, and the enterprises negotiate annual Statements of Corporate Intent (SCIs) with shareholding Ministers. SOEs operate with commercial structures and incentives and with the principal objective of being successful businesses (Ministry of Economic Development New Zealand 2008).

ECNZ was based around three business units:

1. Electricorp Production – to operate the power stations
2. Electricorp Marketing – to market the electricity
3. Transpower – to operate the national grid

There was a fourth unit, PowerDesignBuild, constituted as a subsidiary, to perform design and construction work (Martin 1998).

The low lake inflows of the South Island from November 1991 until June 1992 resulted in a shortage of power that lead to energy conservation by the public. The government cleared ECNZ of the crisis stating that the primary cause of the shortage was the prolonged drought, exacerbated by an unexpected increase in demand. However, the allegation was made that ECNZ was derelict in its duty for deliberately misusing the system. The Electricity Shortage Review Committee concluded that there was no evidence to support the allegation and gave a strong vote of confidence to ECNZ. It was claimed that the occurrence of such a drought was statistically once in every 100 years. The power crisis in

1992 resulted in a loss of public confidence in ECNZ and the media blamed the corporation for the crisis (Mohamed 2004).

In May 1993, the government announced the decision to separate the transmission subsidiary, Transpower from ECNZ. Transpower was set up as a stand-alone SOE, effective from 1 July 1994 (Ministry of Economic Development New Zealand 2009). This marks the start of legal separation of generation and transmission in New Zealand.

5.6.2 Electricity distribution and retail reforms

As described in section 5.3, electricity distribution was initially done primarily by local municipalities. In July 1992, the Energy Companies Act 1992 came into effect, calling for the corporatization of the ESAs. Diverse ownership patterns resulted ranging from trust ownership and private shareholding and combinations of the two. In April 1993, the Electricity Act 1992 became effective whereby the following took place:

- Deregulation (the removal of distributors' statutory monopolies and of the obligation to supply)
- Information disclosure, focused particularly on natural monopolies
- Temporary provision for price control for domestic consumers
- Compulsory maintenance of line services until 2013 (20 years)

This was the first stage of removal of statutory distribution and retail monopolies (and the obligation to supply), allowing competition for sales to retail consumers. In July 1998, the Electricity Industry Reform Act 1998 was effective whereby under the Act, corporate separation of lines and energy businesses was to be achieved by 1 April 1999 and full ownership separation no later than 31 December 2003. In response to the event, the industry chose to move more quickly, completing full ownership separation before 1 April 1999. On that date, there were seven retailers, many owned by generation companies. Merger activity over the period of ownership change was less pronounced among line businesses, of which there were 32 on 1 April 1999 (Ministry of Economic Development New Zealand 2009). This later reduced to 28 in 2004 (Evans and Meade 2005).

5.6.3 Wholesale electricity market formation

By October 1992, the generation sector was still relatively less reformed compared to the distribution and retailing sectors. With the push from the private sectors, in June 1995, the government made the following steps to form the wholesale electricity market - ECNZ was split into two competing SOEs (ECNZ and Contact Energy). ECNZ's Maui gas contract was transferred to Contact Energy. ECNZ's proposal for a new Taranaki plant was sold (including associated gas supply). Six small hydro plants owned by ECNZ were sold. Special constraints on ECNZ were applied until its market share fell to 45% (cap on building new capacity, ring-fencing new capacity, and high level of firm capacity to be offered by tender for long-term contracts).

In 1993, the Electricity Market Company (subsequently renamed M-Co) was set up, to support the electricity market framework for wholesale trading. It was an on-line secondary market in trading of ECNZ's hedge contracts, including provision of market information. A market surveillance committee was established to admit new entrants and supervise conduct. This committee was not government regulated and made up of the ESI representatives. A Metering and Reconciliation Information Agreement (MARIA) was administered to record and reconcile flows to meet the needs of parties contracting in the wholesale and retail markets. Under the MARIA agreement, Transpower, as the National

Reconciliation Manager, reconciles information against contracts and passes information for billing back to market participants (Ministry of Economic Development New Zealand 2009).

In October 1996, the competitive wholesale electricity market started under the New Zealand Electricity Market (NZEM). M-co was contracted to act as Market Administrator, Clearing Manager and Pricing Manager. Transpower took the role of the System Operator, i.e. the scheduler and dispatcher of energy from generation source to the distribution network. At that time, the available generation companies were only Contact Energy and ECNZ. The retailers were companies such as Pacific Energy (formed by a number of distribution companies), Energy Brokers (formed by major commercial and industrial customers), Power Buy and other companies made of combined distribution companies. These retailers were displaced in 1999 when ECNZ was separated into competing generation companies and vertical integration of generation and retailing occurred. The generation companies are Genesis, Meridian Energy and Mighty River Power (see section 5.6.5). When they started their retailing arms, they were able to force other retailers out of business by their bidding strategies.

Electricity prices in NZEM are based on bids and offers from market participants (i.e. generation companies, purchasers and traders), and the price is not capped. Initially, the spot market is supplemented by trading of longer term hedge contracts. However, from 1 March 2004, the NZEM pool was made into a compulsory pool, with the exception of the New Zealand Aluminium Smelter, which has long term contracts in place for the delivery of electricity (Evans and Meade 2005).

5.6.4 The sale of Contact Energy

In February 1996, Contact Energy commenced operations as an SOE generator, in competition with ECNZ. Contact Energy took on the former ECNZ power stations at Roxburgh, Clyde, New Plymouth, Wairakei, Ohaaki, Otahuhu, Stratford and Whirinaki, which represented 22% of the total electricity production. Contact Energy also took over ECNZ's contracts for Maui gas. In March 1999, the sale of a 40% shareholding in Contact Energy was made to U.S.-based Edison Mission Energy for $NZ1.208 billion. The government subsequently sold its remaining share of Contact Energy in May 1999, to more than 225,000 investors at $NZ3.10 per share (Ministry of Economic Development New Zealand 2009).

5.6.5 Further reforms

In April 1999, the ECNZ was split into three competing state-owned generation companies. With the final break up of ECNZ, it now remained only to manage its hedge and debt obligations whilst winding up its other activities.

The new companies, which commenced trading on 1 April 1999 were:

- Genesis Power Ltd - based in Manukau City, owned the Huntly thermal plants and Tongariro hydro power stations
- Meridian Energy Ltd - based in Wellington, owned the South Island's hydro Waitaki river and Manapouri power stations.
- Mighty River Power Ltd - based in Auckland, owned the Waikato river hydro system.

The way these assets were divided posed some opportunities for these companies to exercise their market powers. Following winter shortages in 2001 and 2003, in March

2004, new electricity market arrangements were established under the Electricity Governance Rules and Regulations (enacted in December 2003). The new arrangements terminated the former operations under MARIA. The Electricity Commission (EC) took over responsibility for operating the electricity market (see 5.6.7.2 for further details on the EC). It is also responsible for managing the supply security during dry years by implementing the reserve energy scheme (elaborated further in section 5.12.1).

However, another dry year occurred in the winter of 2008 prompting the government to again review the ESI structure. Several changes were again done to the ESI, this time through the Electricity Industry Bill 2009. These changes are generally known as the Ministerial Review 2009. These review resulted in some measures to improve prices, costs and competition and to improve security of supply.

The measures introduced to improve prices, costs and competition were:

- reconfiguration of SOE assets to reduce some generators market power in the wholesale market in dry years
- requirement for all major electricity generation companies to put in place an accessible electricity hedge market;
- permission for lines companies to get back into electricity retailing, subject to strict controls; and
- establishment of a $15 million fund over three years to promote customer switching between retailers.

Initiatives to increase the security of supply included:

- requiring generation companies or retailers to compensate consumers in the event of conservation campaigns or a dry-year power cut;
- abolishing the reserve energy scheme; and

- increasing the attractiveness of gas exploration and development.

Initiatives to ensure effective governance included:

- abolishing the Electricity Commission and replacing it with a slimmed-down Electricity Authority, with far fewer objectives and functions than the Commission;
- establishing a Security and Reliability Council to monitor Transpower's performance and advise on security of supply; and
- transferring responsibility for grid upgrade approvals to the Commerce Commission.

These changes were made effective in October 2010 (Ministry of Economic Development New Zealand 2010).

5.6.6 The present ESI structure in New Zealand

Following twenty years of gradual transformation of the New Zealand electricity supply industry, the ESI has arrived at its present structure. The New Zealand electricity market is split into the following areas: regulation, generation, administration and market clearing, transmission, distribution and retailing (see Figure 5.1). The details on each area are provided in the following sub sections.

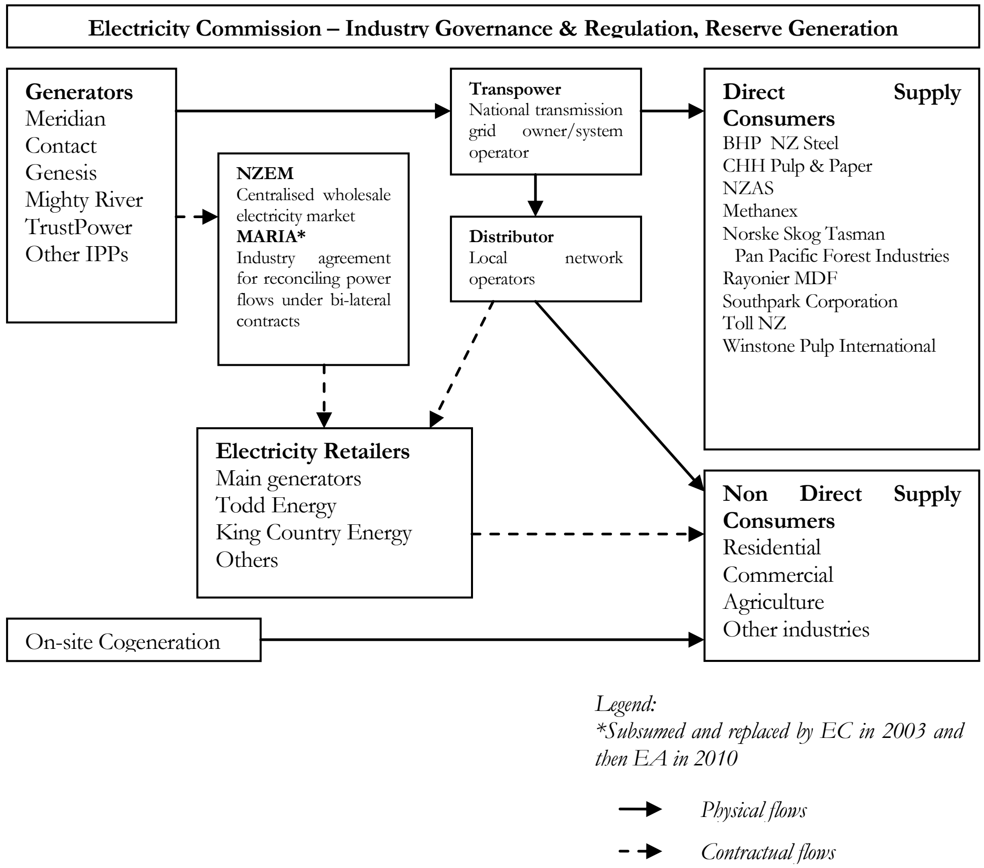


Figure 5.1: Schematic of the New Zealand Electricity Supply Industry – adapted from (Evans and Meade 2005)

5.6.7 Regulators

The main regulator for the competitive ESI as well as other competitive industry in New Zealand is the Commerce Commission (CC). Another regulator that is specific to the ESI is the Electricity Authority (EA) which replaced the Electricity Commission (EC) in October 2010.

5.6.7.1 The Commerce Commission (CC)

In the early New Zealand electricity market reform, the industry was set up to self regulate using demand and supply theory. The only regulator that oversees the industry as well as other competitive industries was the Commerce Commission (CC). This setup was generally known as light handed regulation.

The Commerce Commission is New Zealand's primary competition regulatory agency and was established under section 8 of the Commerce Act 1986. The Commission is an independent Crown entity and is not subject to direction from the government in carrying out its enforcement and regulatory control activities. The Commission's purpose is to promote dynamic and responsive markets so that New Zealanders benefit from competitive prices, better quality and greater choice (Commerce Commission 2009).

The Commerce Commission enforces legislation that promotes competition in New Zealand markets and prohibits misleading and deceptive conduct by traders. The Commission also enforces a number of pieces of legislation specific to the telecommunications, dairy and electricity industries. The Commission also has both an enforcement and adjudication role in the electricity industry under the Electricity Industry Reform Act 1998.

Due to the absence of competition in the lines business, suppliers of electricity lines services are subject to the regulatory provisions under subpart 9 of Part 4 of the Commerce Act 1986 (the Act) from 1 April 2009. They have to adhere to information disclosure regulation and certain performance standards.

5.6.7.2 Electricity Commission (EC)

Prior to 2003, the New Zealand's ESI was self-regulating and appointed an independent Market Surveillance Committee (NZMSC) to oversee its actions. However, because it was appointed by the members of the industry and not backed by any formal government regulator, the NZMSC found it difficult to take positions contrary to the interests of the industry.

New Zealand experienced a sustained period of extremely high wholesale prices during the period June to September of 2001 and again during the period June to September of 2003. In response to the initial period of extremely high spot prices in 2001, two market participants claimed that the high prices were due to the exercise of unilateral market power and prompted the NZMSC to investigate the matter. Despite average prices during June 2001 that were more than 4 times the average prices for the previous year, the NZMSC concluded that, “the Committee does not find that an “Undesirable Situation” in the NZEM existed during 2001 (up to the end of June) and, in particular, in May and June of 2001.” As a consequence, few actions were taken to prevent almost the same sequence of events during the same time period of 2003 (Wolak 2004). The government then decided to abandon the light handed regulation.

The Electricity Amendment Act 2001 allowed the Government to establish an Electricity Governance Board. It provides the Government with the power to make regulations on a number of matters, including: requirement to provide domestic consumers with a low fixed charge tariff option, electricity governance, a complaints resolution system, hydro spill and hedge prices (Ministry of Economic Development New Zealand 2008). The Electricity Governance Regulations were established in 2003, with a seven-member Electricity Commission (EC) to take over governance functions. It began operations on 14 September 2003. The costs of the Commission were recovered from the electricity industry via a levy.

In December 2003, the EC took over responsibility for operating the electricity market from MARIA.

The Commission was responsible for securing reserve generation to ensure New Zealand's electricity needs could be met even in very dry years without power savings campaigns. This involved significant changes to deliver long-term electricity supply security and to curb extreme price volatility in the electricity spot market in dry years. The Commission was responsible for managing the electricity sector so that electricity demand could be met even in a 1-in-60 dry year, without the need for national power conservation campaigns. It did this by contracting with generation companies for the provision of dry year reserve generation capacity and fuel.

The EC was also responsible for modelling and forecasting future demand and supply conditions in the industry and determining transmission investment and pricing. As part of this obligation, they published the Statement of Opportunities (SOO) (more details on SOO in section 5.13) once every two years to provide the market players with information on load demand forecasts and possible future scenarios resulting from various government policies. Based on the SOO, Transpower then needed to publish an Annual Planning Report (APR) to provide information to the ESI on its investment plans. These publications were intended to help the market players with their future investment decisions.

5.6.7.3 Electricity Authority (EA)

Since 1 November 2010, the Electricity Authority (EA) (Electricity Authority 2010) has overseen the New Zealand’s ESI. The Electricity Authority is an independent Crown entity under the Crown Entities Act and is responsible for promoting competition, reliable supply and efficient operation of the electricity market for the long-term benefit of consumers. The Electricity Authority's key functions include (Ministry of Economic Development New Zealand 2010):

- making and administering the rules governing the electricity industry through an Electricity Industry Participation Code;
- monitoring compliance with the code and other provisions in the Electricity Industry Act and regulations and take enforcement action;
- undertaking market facilitation measures such as education and providing guidelines, information and model arrangements;
- industry and market monitoring, and carrying out reviews, studies and inquiries into matters relating to the industry; and
- contracting for market operation services and system operator services.

The main difference between the EC and the EA is that the EA will have less control over the operations of the ESI (such as transmission expansion), is no longer involved with work on energy efficiency. With the Ministerial Review in 2009, through the abolishment of the reserve energy scheme and making it a requirement for retailers to pay consumers in the event of a conservation or dry year power cuts, EA it is not responsible for any future dry year shortages.

5.6.8 Generation companies

Electricity generation in New Zealand today is dominated by five companies - Meridian Energy, Contact Energy, Genesis Energy, Mighty River Power and TrustPower. They are major players in New Zealand's electricity supply industry where they are all active in generation, the wholesale market and retail sales of electricity. Table 5.1 shows the companies' profiles which were obtained from their latest annual reports. These five companies combined produce or control more than 95% of New Zealand's total electricity generation.

Table 5.1: New Zealand's main generation companies

Company	Capacity (MW)	Ownership
Contact Energy	2,070	Public
Genesis Energy	1,977	SOE
Meridian Energy	2,601	SOE
Mighty River Power	1,369	SOE
Trust Power	594	Public

Some smaller generation power plants exist, most of which are associated with major industrial processes (cogeneration). There are a number of smaller companies in the electricity generation industry including WEL Networks, NZ Windfarms, Todd Energy, NZ Energy, MainPower and Top Energy (Electricity Commission 2008).

Generation companies own and operate power stations across the country. Most of New Zealand's electricity is generated at remote locations and requires an efficient transmission system to transport it to the main demand centres. Around 40 sites supply electricity to the national grid. Some of the smaller scale generation is embedded and feeds directly into local distribution networks.

Currently, approximately 60% of New Zealand's electricity is generated by hydro stations, with the balance from geothermal stations, gas, coal and oil-fired thermal stations, biomass plants and wind farms (New Zealand Ministry of Economic Development 2009). More details on the generation trends in New Zealand are provided in section 5.10.

5.6.9 Spot wholesale electricity market

The spot wholesale electricity market in New Zealand is known as the New Zealand electricity market (NZEM). It was initially created by the ESI via a multilateral agreement as a voluntary self regulating market, and began full operation on 1 October 1996. Initially, about 80% of the electricity consumed in New Zealand was voluntarily traded through the NZEM. The remaining electricity was transacted through bilateral contracts between generation companies, retailers and major users outside the market. From 1 March 2004, the NZEM pool was made into a compulsory pool, with the exception of the New Zealand Aluminium Smelter, which has long term contracts in place for the delivery of electricity (Evans and Meade 2005). It is an energy only pool where the wholesale electricity prices are determined in NZD per MWh.

At its establishment, the NZEM adopted guidelines given by the government to assess market participant behaviour and rule changes. They required the NZEM to collectively foster efficient and competitive markets, enable entry of new buyers and sellers, comply with the law, be robust and enforceable and maintain a certain process to set and change rules.

Initially, these were overseen by the NZEM Rules Committee, with compliance monitored by an independent Market Surveillance Committee. The monitoring function was then taken over by EC in 2003 and then the EA in 2010. M-Co (M-Co 2010) was initially set up by the industry as the Electricity Market Company and responsible for the development of the NZEM. It then acted as:

- the market administrator
- pricing manager - calculates and publishes final prices based on actual supplies and demands
- clearing manager – settles the market

The operation of the NZEM is elaborated on in section 5.7.

5.6.10 Transmission

The transmission system in New Zealand has the following characteristics (Evans and Meade 2005):

- Long and sparse lines due to New Zealand's geography and load distribution
- Completely isolated from the network of any other country
- Major demand centres are in the North Island whereas the major hydro generation capacity is in the South Island. However, the largest electricity consumer is the New Zealand Aluminium Smelter at Tiwai Point, Bluff at the bottom of the South Island. It takes 15% of the annual electricity demand.
- The 350kV high voltage direct current (HVDC) lines between Benmore in the South Island and Haywards in the North Island, comprised of 570km of overhead

lines and 40km underwater across Cook Strait, is vital in providing electricity exchange between the two main islands

Transpower transmits power at high voltages to the distribution companies and also to some direct large power customers such as BHP NZ Steel (near Auckland) and Methanex (near New Plymouth). Besides acting as the dispatcher of electricity supply as determined from the spot wholesale market, Transpower also acts as the System Operator (SO) to manage the physical characteristics of electricity supply to ensure system-wide security and supply quality.

5.6.11 Distribution

As of December 2010, there were 28 lines companies that owned the local distribution networks throughout New Zealand. The ownership of distribution companies is a mix of public listings, shareholder co-operatives, community trusts and local body ownership, with most lines companies being owned by trusts (Evans and Meade 2005). Lines companies differ in size, with one company (Vector) making up one third of the sector (by number of connections), and the largest four (Vector, Powerco, Orion and Unison) supplying 66% of all connections. Vector operates in Auckland, Powerco in the lower North Island, Orion in Christchurch and Unison in Hawkes Bay, Taupo and Rotorua. The lines companies are connected to the national grid, and for the most part sell their services to retailers, although some distribution companies contract directly with connected consumers. Most consumers are connected to the local distribution networks.

5.6.12 Retail companies

The retail market is a market where electricity retailers compete to sell the electricity they have purchased on the wholesale market to consumers, including small-scale industrial and commercial users and domestic consumers. Retailers can also purchase electricity directly from embedded generators (smaller generators connected directly to distribution networks such as from biomass, landfill, and wind turbine generation) (Electricity Commission 2009). The retail space is dominated by the five main generation companies as discussed in section 5.6.8.

5.7 NZEM operation

In determining the prices for the wholesale electric energy, NZEM uses a transparent pricing mechanism to ensure balance between electricity supply and demand in 48 half-hour periods, trading each day, at each of the 244 nodes on the national grid. Its operation is shown in Figure 5.2.

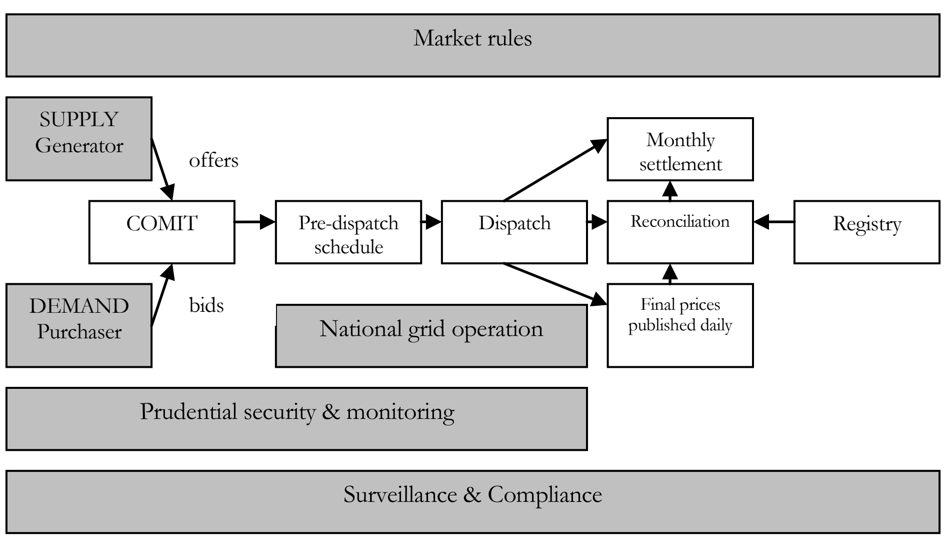


Figure 5.2: New Zealand's wholesale electricity market (Evans and Meade 2005)

NZEM services are provided via contestable contracts. The Commodity Information and Trading (COMIT) system provides an internet based means for generation companies to submit offers and purchasers to submit bids at each node up to 36 hours before dispatch (Commodity Information and Trading system (COMIT) 2010). Information on how generators are anticipated to meet demands is provided by the scheduler, Transpower, which, as dispatcher, also matches actual demands and supplies in real time to ensure physical balance (Evans and Meade 2005).

Generation companies compete to generate based on the price they offer to generate at. These offers are submitted via a secure internet site, where they are loaded into a complex solving program known as Scheduling, Pricing and Dispatch (SPD) which is set up to minimise the final cost to consumers for each trading period. This solving program considers the offers of generation companies, expected demand, constraints on high voltage lines, and line losses to produce an expected price and level of generation for market participants. Information is received by the various market participants on expected generation levels and prices, and from here they make further decisions on how they will conduct their trading activities.

Transpower, the System Operator, then uses the above information to produce dispatch instructions using the solving program, which it issues to all power stations around New Zealand via a computerised dispatch tool at least every half hour of the day. A dispatch instruction tells the generator how much to generate, how much reserve to be available, whether or not the station is the frequency keeper and information on other ancillary services such as voltage support. Generation companies receive payments for their output by selling into the NZEM compulsory pool where it is transported from generation source to GXP along the high voltage network, and from here it is paid for by consumers and retailers (Genesis Energy 2010). From 1 March 2004, the NZEM pool was made into a compulsory pool, with an exception of the New Zealand Aluminium Smelter, which has long term contracts in place for the delivery of electricity (Evans and Meade 2005).

5.7.1.1 Price determination in NZEM

In New Zealand, the prices are ex post where the payment is determined after the load dispatch when the actual load demand is already known and the actual price have been determined (from the actual intersection of the supply and demand curve) (Evans and Meade 2005) . Prices are determined at each GIP and GXP for each half hour trading period of the day. Prices are discovered from generation offers, demand, transmission constraints and line losses. An example is provided below to illustrate the price determination (Genesis Energy 2010).

As an illustration, assume the NZEM has three generators - Gen 1, Gen 2 and Gen 3, each with 200 MW of installed capacity. For a particular trading period, all generators can offer in their generation using up to five price bands (NZD per MWh). Each price band must have a number of MW attached to it as shown in Figure 5.3. Each generator submits its offers to the Market via New Zealand's Electricity Market trading platform COMIT and this information is then passed on to Transpower. Transpower gathers all the offers together and stacks them in order from lowest to highest price and then using its forecast demand, determines how much electricity it is going to need to meet demand for a particular half hour.

Gen 1		Gen 2		Gen 3	
Price	MW	Price	MW	Price	MW
$120.01	20	$150.02	10	$110.03	25
$70.01	40	$75.02	30	$65.03	50
$55.01	40	$25.02	50	$45.03	25
$35.01	50	$15.02	30	$10.03	40
$0.01	50	$0.02	80	$0.03	60

Price	MW	Cumulative MW
$150.02	10	600
$120.01	20	590
$110.03	25	570
$75.02	30	545
$70.01	40	515
$65.03	50	475
$55.01	40	425
$45.03	25	385
$35.01	50	360
$25.02	50	310
$15.02	30	260
$10.03	40	230
$0.03	60	190
$0.02	80	130
$0.01	50	50

Gen 1		Gen 2		Gen 3	
Price	MW	Price	MW	Price	MW
$75.02	180	$75.02	175	$75.02	175

Figure 5.3: Price bands example offered by generators (Genesis Energy 2010)

If for example the system demand was to be 530 MW for a particular half hour period, this would result in the price of $75.02 (as highlighted in Figure 5.3). All the offers below this price will then be accepted (successful bids) resulting in Gen 1 being dispatched to generate 180 MW, Gen 2 being dispatched at 175 MW and Gen 3 also being dispatched at 175 MW. All generators get paid the marginal price for their generation. The price is set by Gen 2's $75.02 price band, and as it is the marginal generator, it only gets dispatched 15 MW of its

$75.02 band. In this example, the revenue for each generator is equal to (Price*MW)/2. Revenue is divided by two because the trading is done in half hour periods – not full hours.

5.7.1.2 The financial flows in the market

All electricity dealings are carried out via the compulsory pool which means that all electricity generated goes into a pool and flows out of the pool via GXPs dotted along the high voltage transmission network. The first step involves the discovery of price, as determined by the generators' offers, level of demand, and transmission losses and constraints. This sets the price at each node and generators get paid the price at their GIP. The electricity flows onto the national grid and then exits at over 250 different GXPs around New Zealand, flowing onto distribution networks where it is then delivered to end users. Each GXP sees different wholesale prices to take into account transmission costs. The different prices are known as Locational Marginal Prices (LMP). At the GXP there is also a price which is paid by either the retailing companies, customers paying spot prices, or generation companies providing a hedge contract. At the end of the month retailers determine how much their customers have used by reading meters at the Installation Control Points (ICP) level and then sum them back to the GXP level for each trading period of the month, determining the totals they have to pay for spot purchases for a particular month. Figure 5.4 shows the overview of the price flow from the pool to the consumers.

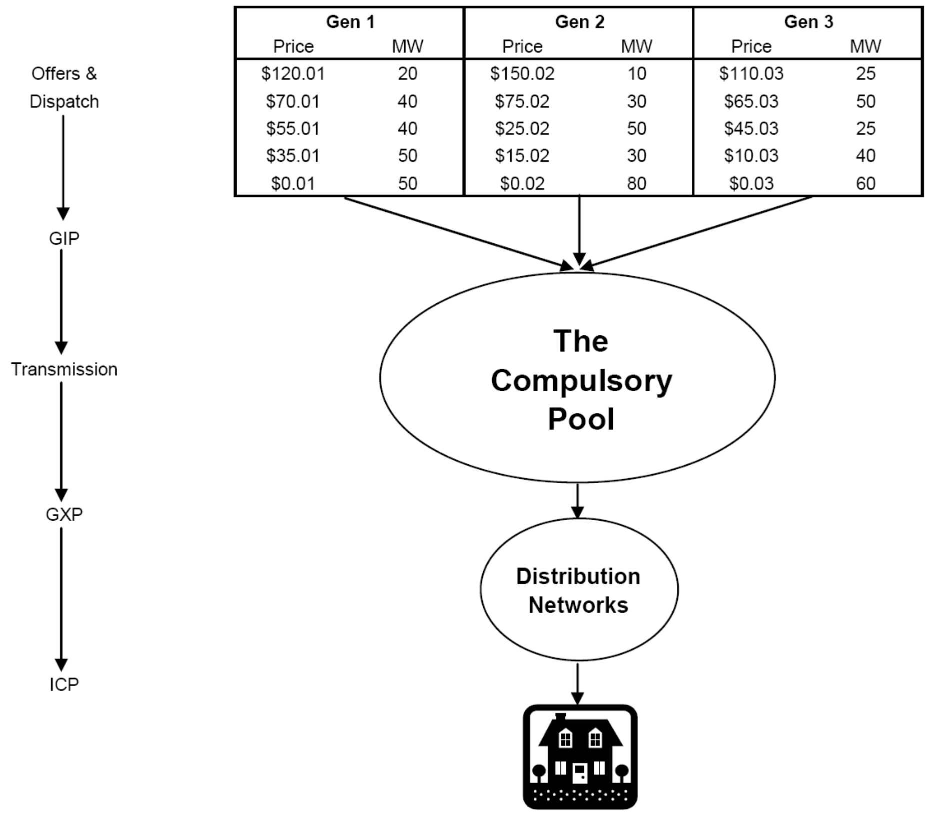


Figure 5.4: Overview of the NZEM price flows (Genesis Energy 2010)

5.8 Ancillary services

Since the compulsory pool is an energy trading pool, the ancillary services are provided using other arrangements. The arrangements are done via a reserve market and a frequency keeping market.

5.8.1 The reserve market

As part of the System Operator responsibilities, Transpower is required to ensure that enough generation is kept in reserve to cover the risk of large generators or HVDC tripping, and to ensure that the system frequency is kept at around 50 Hz in both the North and South Islands. Generation companies and load bearers (such as distribution networks) with interruptible load (i.e. controllable load such as water heating), offer the reserve capacity to Transpower. There are two types of reserve required – Fast Instantaneous Reserve (FIR) and Slow Instantaneous Reserve (SIR). FIR is required to respond within 6 seconds of the frequency falling below the nominal frequency of 50Hz and sustain this extra generation for at least 60 seconds. SIR is required to respond within 60 seconds of the under frequency event and be maintained for up to 15 minutes if required.

The pricing algorithm that the System Operator runs co-optimises the Energy and Reserve markets such that the lowest cost to the consumer is reached. This means that the energy and reserve markets can affect each other. When the market is short of reserve, a generating unit may be backed off to provide reserve even though its energy offers are below the clearing energy spot price. This may result in a higher spot price as it draws volume out of the energy market into the reserve market. In times when energy prices are lower than reserve prices, the risk setter may be backed off to reduce the amount of reserve required to produce the least cost to the market (Genesis Energy 2010).

5.8.2 The frequency keeping market

The frequency keeping market is a separate market from the energy market, in that the companies providing frequency keeping compete by offering a fee for the service for each half hour trading period. The frequency keeper is required to maintain frequency within a band of 50.2 Hz to 49.8 Hz as required by the System Operator's primary objectives.

As demand and generation fluctuates from second to second, the frequency either falls or rises and the frequency keeper must have a band of plus or minus 50 MW from its dispatched set point to keep frequency at the level identified above. Governors on each generator monitor the frequency and control the amount of water or steam flowing through the turbine to adjust the level of generation to suit the frequency level.

For example, if electricity generation is constant and demand suddenly increases, the frequency falls, requiring more electricity to be generated to get the frequency back to 50 Hz. As a result of this, the frequency keeper increases its generation to stabilise the frequency. Conversely, if generation is constant and demand falls, then the frequency increases, which requires the frequency keeper to decrease output (Genesis Energy 2010).

5.9 Unique characteristics of NZEM

The principles behind the NZEM are very similar to other markets around the world; however, geographic features bring a uniqueness to it. They can be summarised as follows:

(i) Hydro dominance in the generation mix

(ii) Long and sparse transmission network

(iii) The importance of the HVDC link in balancing the price between the two main islands

(iv) Trading behaviours

These features are discussed in more detail in the following sub-sections.

5.9.1 Hydro dominance in the generation mix

New Zealand's mix of generation is highly skewed towards hydro generation, with at least 60% of generation coming from hydro sources, as shown in Figure 5.5. The data table is provided in Appendix B3. New Zealand's hydro storage capacity is also relatively small in comparison to other hydro reliant countries around the world (Genesis Energy 2010). Hence, the NZEM is highly influenced by hydro storage levels and prices can reach high levels during dry weather. As the gap between supply and demand diminishes – the risks associated with dry years are exacerbated.

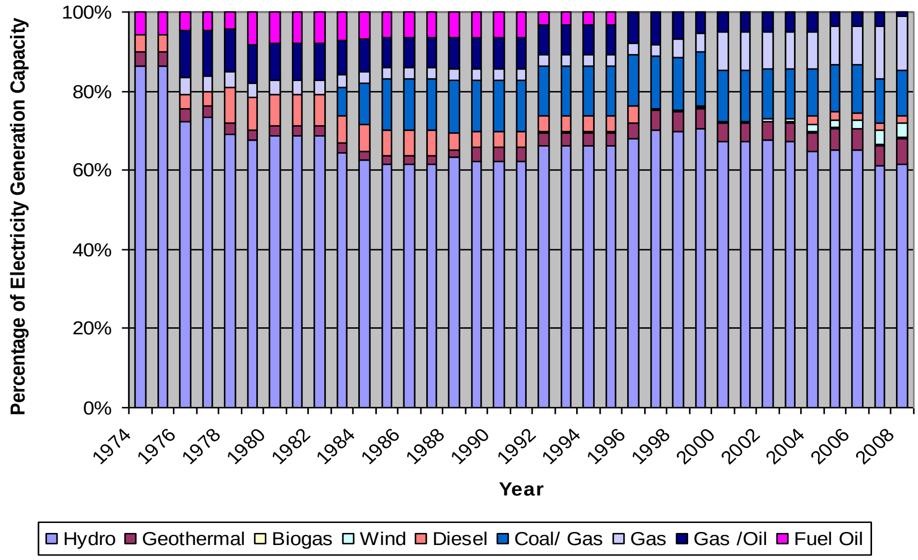


Figure 5.5: The electricity generation fuel mix in New Zealand from 1974 to 2008 (Ministry of Economic Development New Zealand 2008)

5.9.2 The impact from the transmission networks

New Zealand is a long and relatively thin country, with major generation sources and demand centres separated not only by large land distances, but the Cook Strait separating the two main islands. Thus New Zealand relies on a high quality transmission network that allows generation companies to transport their electricity from generation source to end-users without significant losses. New Zealand's high voltage transmission network has 220kV and 110kV a.c. lines with a high voltage direct current (HVDC) overhead line/submarine cable system joining the North and South Island networks. Network congestion and failures can have strong impacts on wholesale electricity prices.

The two main islands in New Zealand have different demand and supply characteristics. The North Island (NI) has the two major cities, Wellington and Auckland, and 80% of the total population (International Energy Agency 2006). The 2009, electricity consumption in the NI was 23.8GWh as compared to 13.6GWh in the South Island (SI) (Electricity Commission 2010). In December 2008, the NI had an installed capacity of 5.8GW whereas the SI had 3.6GW (Ministry of Economic Development New Zealand 2008). The power plants in the SI are all renewable, whereas the NI has all the thermal plants in New Zealand. However, the SI has the largest electricity consumer, the Tiwai Aluminium Smelter, consuming about 15% of the annual national electricity consumption (Evans and Meade 2005). As a consequence, the cheaper electricity resources are tapped from the SI and sent north, whereas during dry seasons, the electricity is supplied from the thermal plants in the NI. This is done using the HVDC link that connects the two islands.

Figure 5.6 shows the electrical energy that has been generated in the NI and the SI respectively between 2003 and 2010. It shows that most of the time within the duration, more electricity is generated from the NI. The electricity generation from the SI which is hydro dominated is reduced during dry winters such as in 2003 and 2008 and during the HVDC loss in January 2004.

Figure 5.7 shows the annual energy transfer using the HVDC link. Comparing the two figures, it can be deduced that most of the energy generated in the NI is consumed there, whereas most of the energy in the SI is sent northward except when hydro resources are limited due to the weather.

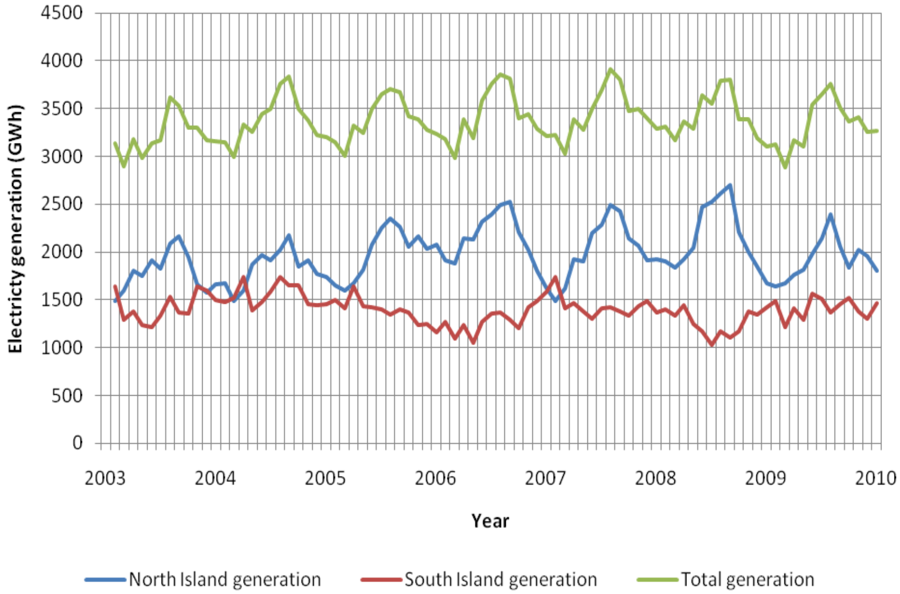


Figure 5.6: Electricity generated in New Zealand from 2003 to 2010

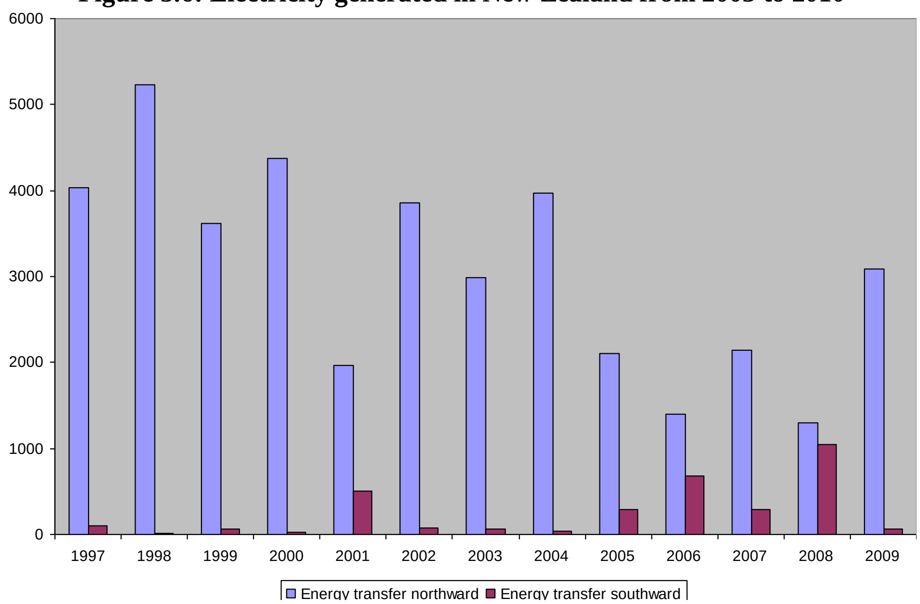


Figure 5.7: Annual energy transfer using the HVDC link from 1997-2009

The typical generation and transmission scenario described in the previous paragraph balances the electricity prices in the two islands. The HVDC link can have a major impact on the spot market price as it can cause the wholesale price for the North and South Islands to decouple significantly if it breaks down. Figure 5.8 shows the plot of wholesale electricity prices at Otahuhu (North Island) and Benmore (South Island) in January 2004.

During an HVDC outage between 8th and 13th January, the prices in the two islands decoupled. The electricity prices for the SI reduced (since the SI had ample cheap hydro supply) whereas the prices for the NI increased significantly due to the operation of thermal plants required to meet the demand there.

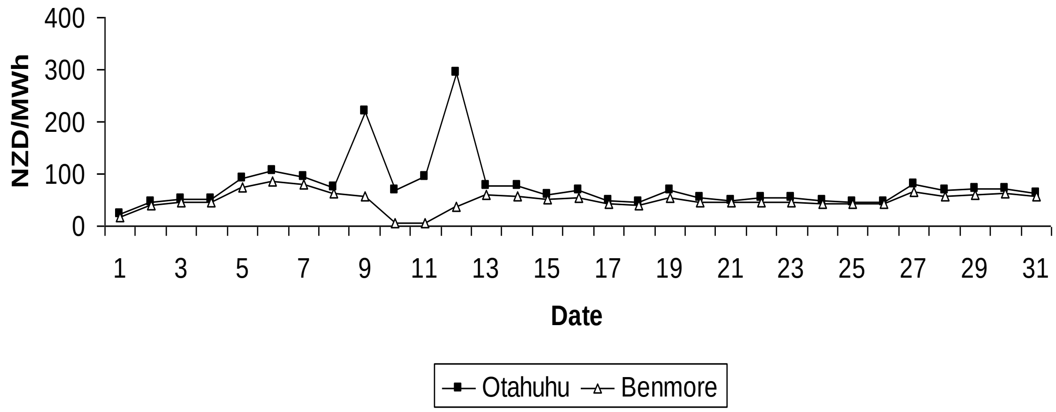


Figure 5.8: Electricity prices at Otahuhu (NI) and Benmore (SI) in January 2004

5.9.3 Trading behaviours

Another unique characteristic of the NZEM is that vertical integration is allowed between generation and retailing, resulting in the main retailers being generation companies (known as ‘gentailers’ (Evans and Meade 2005)). Generation companies generally sell their output to a retailer. However, the gentailers have to purchase the energy at a grid exit point before supplying electricity to the consumers. Therefore, they will have the cost of purchasing that electricity to consider when submitting their bids into the NZEM. High wholesale electricity prices increase generation companies’ profits while reducing retailers’ profits. Allowing vertical integration between generation and retail is believed to provide a natural and an efficient hedge against generation companies abusing their market power (Evans and Meade 2005). On the other hand, due to the gentailers' ability to bid strategically, they quickly forced out other competitors and dominated the retail sector.

5.10 Generation trends in New Zealand

New Zealand has mountainous regions and many water bodies allowing it to have a high hydro electricity potential. Thus, hydro has always dominated the generation mix (see Figure 5.5).

As the demand for electricity continued to increase, a range of thermal projects based on technology using coal, gas and oil, were examined from the early 1960s. The gas discovery at the Maui field in 1969 led the Power Committee to reintroduce the possibility of gas fired thermal plants. However, from 1975, the government became less keen on using gas for electricity and began to explore other possible uses of gas. This led to projects like ammonia-urea, methanol and synthetic petrol plants in Taranaki, converting natural gas into a variety of products in the early 1980s (Mohamed 2004).

The use of oil in power plants in New Zealand was limited by the global oil price hike in the mid 1970s and cheaper alternative resources available from natural gas and from the hydroelectric generation in the SI. After the decommissioning of Marsden A in 1985, the new generation came from oil fired plants. Marsden B was an unused 250MW oil fired power station near the Oil Refinery at Marsden Point in Northland. Due to rising oil prices, the plant was mothballed in 1978 without ever being commissioned. In 2004, Mighty River Power proposed modification of Marsden B for operation on coal. The proposal received much opposition and had to be abandoned. There has been no coal plant proposed since then. The plant was sold and the components dismantled and shipped to India. Generation from oil only commenced again in 2003 after the Electricity Commission decided to build the Whirinaki power plant to run during dry hydro years.

Currently, wind power is on the rise in New Zealand. However, it has been observed that wind resources are less during dry years (Leyland 2009). Therefore, thermal plants still prove to be the reliable options to support hydro fluctuations.

5.11 Generation costs in New Zealand

The costs associated with building power plants in New Zealand is believed to be on the rise (Genesis Energy 2010). The costs associated with applying for resource consents via the Resource Management Act 1991 are extensive and the consents take a long period of time to be considered. They are not guaranteed to be granted.

The marginal costs of operating thermal generation are also on the increase. Thermal generators use either coal or gas to fire their boilers and the cost associated with gaining access to these fuels has been on the increase. In particular, with the diminishing Maui gas field, it appears New Zealand’s cheap gas sources are drying up. Also, the costs associated with creating new coal mines is on the increase. On 1 July 2010 the New Zealand Emissions Trading Scheme (ETS) commenced and included the electricity sector.

The simplest economic rule states that price must be greater than marginal cost to make running of any type of plant economic in the short run. Therefore economic theory suggests that as short-run marginal costs (SRMC) increase, generators’ offers will reflect this, hence the upward movement of wholesale prices.

5.12 Problems faced in the NZEM

Since the ESI restructuring in New Zealand, several problems have occurred. The problems concern dry year shortages and market power.

5.12.1 Dry year winter shortages

New Zealand, with its heavy reliance on hydropower, has one of the lowest electricity prices in the OECD. However, its high hydro dependence, coupled with its lack of interconnection with other countries, has created risks of a shortfall of electricity production capability when there is a lack of rainfall (World Energy Council 2004). Even though dry years are not new to New Zealand, they have caused more electricity shortages after the ESI restructuring. Shortages occurred around the winter time of 1992, 2001, 2003, 2006 and 2008 due to high demand accompanied by a lack of hydro resources. The electricity demand in New Zealand is typically higher in winter due to space heating.

In 2001, electricity prices soared through a combination of relatively low rainfall and colder than normal weather (Figure 5.9). Wholesale prices increased ten times (from NZD 40 to 400/MWh), causing hardship to some retailers who had not adequately hedged. One large retailer was forced to leave the market. The government intervened through an energy conservation campaign that helped to avert further supply shortfalls (World Energy Council 2004).

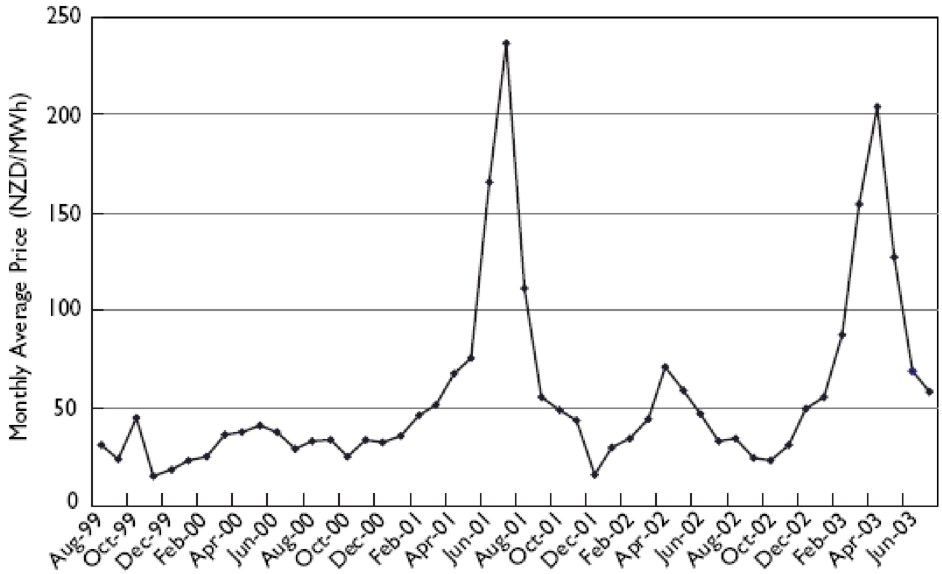


Figure 5.9: Monthly averages of New Zealand wholesale electricity prices (August 1999- July 2003) (World Energy Council 2004)

Two years later, the electricity system went through a similar energy shortfall with prices beginning to rise in April 2003. The shortfall was caused by a prolonged period of low hydro inflows, and concerns about the availability of gas and coal for thermal generation. A successful energy conservation campaign combined with higher rainfall heading into the winter averted power shortages.

After the 2003 shortage, the government concluded that the electricity market did not provide enough incentive to invest in generating capacity that would provide sufficient supply in very dry years. The government was particularly concerned that some of the existing thermal generating capacity would be scrapped because of insufficient commercial incentives to keep it operating. Its main policy proposal was to create an Electricity Commission to take reasonable steps to ensure security of supply even in a "1 in 60" dry year without the need to resort to an emergency conservation campaign. The commission was to contract for reserve energy to be withheld from the market during normal years and made available only during dry years. The reserve energy would be offered into the market once the spot price began to exceed a certain level and was expected to reduce price volatility. The government stated that this policy should avoid the industrial production losses caused by the high spot prices as well as the public inconvenience associated with the energy savings campaigns (International Energy Agency 2003).

In July 2003, the government announced that a new 155MW oil-fired power plant would be built before winter 2004 to help provide increased certainty of electricity supply. It was sited at Whirinaki, Hawkes Bay, to provide reserve generation for use during very dry periods when hydro lake inflows were abnormally low. It would also provide reserve generation to cover major breakdowns in other generating plant. Contact Energy installed and operated the government-owned plant at its Whirinaki site. This 155MW station was commissioned on 1 June 2004, and was intended to help provide increased certainty of electricity supply. It would only run when the limits of the electricity system were tested by problems such as low inflows to the hydro lakes or a major generation or transmission breakdown (Ministry of Economic Development New Zealand 2009).

5.12.2 Market power

In May 2009, the Commerce Commission (CC) released a report on their investigation on market power abuse in the ESI in New Zealand. The investigation led the CC to the view that the four main generation companies – Contact Energy Limited (Contact), Genesis Power Limited (Genesis), Meridian Energy Limited (Meridian) and Mighty River Power Limited (Mighty River Power) - have a substantial degree of market power in the wholesale electricity market. The CC’s analysis, based upon quantitative evidence provided by Professor Frank Wolak (Wolak 2009), suggested that since the formation of the NZEM in October 2003, the generation companies exercised their substantial market power to earn market rents estimated conservatively to be $4.3 billion. Over a period of six and a half years, the amount averaged to 18 percent of the total wholesale market revenues received by all generation companies. The exercise of market power to earn profits is not by itself a contravention of the Commerce Act, but is a lawful, rational exploitation of the ability and incentives available to the generation companies (Commerce Commission 2009).

Due to the way ECNZ was broken up, the resultant generation companies were able to exercise some market power under different circumstances. For example, Genesis and Contact Energy had the thermal plants, whereas Meridian Energy had only hydro and wind plants. This allowed the thermal plant owners to set the wholesale market price during low hydro availability. The asset location of the companies may also have an impact on their market power (Meridian Energy's plants were in the SI whereas the Genesis and Contact Energy plants were in the NI).

Hence, starting October 2010, the following changes were made:

- transferred Tekapo A and B power stations in the South Island from Meridian Energy to Genesis Energy, and the government-owned Whirinaki in the North Island to Meridian Energy;
- requiring Meridian Energy, Genesis Energy and Mighty River Power to undertake "virtual asset swaps" through a 15 year contract, ensuring the ability of each company to provide increased competition in the island where they currently had little or no generation capacity

5.13 Electricity planning in New Zealand

Prior to the ESI restructuring, the need for systematic planning arose as a consequence of severe problems of supply in 1953 to 1954 with the increasing demand in the North Island. In 1953, the supply authorities formed a Power and Finance Utilisation Committee to estimate future demand. They estimated that there would be an annual increase of 9.8% until 1958 and that the demand growth in the North Island would be more than in the South Island. In 1955, both the government and the supply authorities initiated planning reports. They produced the 'First Report of the Combined Committee on the North Island Electric Power Supply', which initiated a system for annual planning reports (Martin 1998).

In 1976, the government changed the parameters of planning with restrictions on government spending. This resulted in a number of projects being deferred and the bulk supply tariff substantially increased. More emphasis was placed on energy conservation. The Electricity Amendment Act No. 1 of 1976 made it a goal to reduce the growth of the demand by promoting measures to achieve greater efficiency in electricity usage. People became more aware of ways to reduce their bills by home insulation and off peak storage heating (Martin 1998).

In 1980, the Power Planning Committee and the Forecasting Committee combined and produced the first Energy Plan. Their reports suggested that considerable additional capacity would be required from 1985. This initiated a number of other projects. The last Energy Plan was published in 1985, and after a less thorough Energy Issues Paper in 1986, the publication of public planning documents of the kind produced since the mid 1950s came to an end (Mohamed 2004). Long term planning in New Zealand ceased with the abolition of the Ministry of Energy in December 1989.

After 2003, with the establishment of the EC, a new kind of coordinated planning was introduced with the publication of the Statement of Opportunities (SOO) once every 2 years (Electricity Commission 2009). The basic assumptions made in formulating the model for the SOO is based on the New Zealand energy policies (discussed in the following sections). The purpose of the SOO was "to enable the identification of potential opportunities for efficient management of the grid, including investment in upgrades and transmission alternatives (Electricity Commission 2008)." Unlike central planning, the SOO was not a plan for future development of the grid or generation but provided the market players with information for their future investments under various future scenarios. The first SOO was published in 2005, followed by others in 2008 and 2010. Under the new ESI arrangement with the EA, it is not certain whether there will be another publication of a SOO and who will be publishing it.

This research used the Statement of Opportunity 2008 (SOO2008) as its main reference in the model development. The SOO2010 was only finalised in September 2010 (Electricity Authority 2011) when all the analyses had been completed in this research. Some of the updates that were made for SOO2010 are:

- Updated load forecasts
- Price updates for coal and lignite and carbon charge
- Assumptions for all scenarios remain the same except for the high coal utilisation scenario. In SOO2010, it is no longer assumed that the demand side management is high

- Introduce photovoltaic and reciprocating engine technology as energy resources

These updates are minor and do not affect the fundamental principles of the SD model developed in this research.

The scenario development process for the 2008 generation scenarios are described in detail in Chapter 7. Five scenarios were developed, intended to provide reasonably credible future possibilities, while encompassing most of the uncertainties (Electricity Commission 2008). The five scenarios were Sustainable Path, South Island Surplus, Medium Renewables, Demand Side Participation and High Fas Recovery. They will be discussed further in Chapter 7. These scenarios were suggested by the New Zealand Energy Strategy 2007 (NZES2007) (see Section 5.14.1).

5.14 New Zealand's energy policy

The abolition of the Ministry of Energy in December 1989 ended the government's direct regulation over the industry. However, in June 1992, the Government confirmed its energy policy framework to be the following:

"The Government's key objective in the energy area is to ensure that energy services continue to be available at the lowest cost to the economy, consistent with sustainable development. This will be achieved by the efficient and effective provision of energy services through properly functioning commercial systems with competitive incentives. These systems will work within an effective and stable regulatory environment and take energy conservation into account." (Ministry of Economic Development New Zealand 2008)

In June 1993, the policy on renewable energy was declared. The framework consisted of the following objective:

"To facilitate the development of cost-effective renewable energy consistent with the Government Energy Policy Framework." (Ministry of Economic Development New Zealand 2008)

The government's energy sector reforms were seen as a good basis for encouraging renewable resources. Enhancements of the opportunities for the cost-effective application of renewable energy were announced, including work on identification of the barriers to renewable energy. In October 2000, a revised Energy Policy Framework was released in line with the major restructuring conducted in 1998. The Government's overall objective was:

"to ensure the delivery of energy services to all classes of consumers in an efficient, fair, reliable and sustainable manner." (Ministry of Economic Development New Zealand 2009)

To provide New Zealand energy needs while maintaining a clean environment to live in, a sustainable development approach was adopted by the government. Sustainable development is defined as *"development which meets the needs of the present without compromising the ability of future generations to meet their own needs"* (Ministry of Economic Development New Zealand 2007). Achieving sustainable development involves a different way of thinking and working. It requires looking after people's needs, taking long-term views into consideration, taking account of the social, economic, environmental and cultural effects, and encouraging participation and partnerships from all parties involved. In view of sustainability, the New Zealand government's energy policy objectives were outlined in policy statements on natural gas and electricity and in the government's energy strategies. New Zealand's government identified three essential building blocks for a sustainable energy future, which were - energy efficiency, energy conservation and renewable energy systems.

In implementing the policy, two strategies have been prepared:

(i) New Zealand Energy Strategy (NZES) and
(ii) National Energy Efficiency and Conservation Strategy (NZEECS)

Both the strategies were formed to achieve higher energy efficiency with improved comfort, lower costs and reduced greenhouse gas emissions (Ministry of Economic Development New Zealand 2007). The government set a target for 90 per cent of electricity to be generated from renewable sources by 2025.

5.14.1 New Zealand Energy Strategy to 2050 (NZES)

The first New Zealand Energy Strategy (NZES) is known as "New Zealand Energy Strategy to 2050 – Powering Our Future" which was published in October 2007 (Ministry of Economic Development New Zealand 2007). Through the first NZES, the government laid out their energy vision for New Zealand to be "a reliable and resilient system delivering New Zealand sustainable, low emissions energy services, through:

- Providing clear direction on the future of New Zealand's energy system
- Utilising markets and focused regulation to securely deliver energy services at competitive prices
- Reducing greenhouse gas emissions, including through an emissions trading scheme
- Maximising the contribution of cost-effective energy efficiency and conservation of energy

- Maximising the contribution of cost-effective renewable energy resources while safeguarding our environment
- Promoting early adoption of environmentally sustainable energy technologies
- Supporting consumers through the transition.

The main features of the NZES 2007 are summarised in Table 5.2.

Table 5.2: The targets and strategies in NZES 2007

Targets	Strategies
Resilient, low carbon transport	▪ Updating the New Zealand Transport Strategy in 2008 ▪ Developing policies to encourage greater provision of public transport, cycling and walking ▪ Developing a New Zealand Domestic Sea Freight Strategy ▪ Developing average fuel economy standards for light vehicles at point of import ▪ Establishing an expert advisory group to look at future vehicle technologies, such as bio fuels and electric cars ▪ Introducing the Biofuels Sales Obligation on 1 April 2008
Security of electricity supply	▪ Reviewing the reserve energy policy to determine whether any additional measures are required ▪ Developing national guidance under the Resource Management Act for electricity transmission ▪ Introducing amendments to the Electricity Industry Reform Act to relax some conditions around investment by lines companies ▪ Promulgating regulations for distributed generation ▪ Developing gas wholesale and transmission market arrangements to make it easier to establish more flexible and secure gas supply arrangements
Low emissions power and heat	▪ Deciding "in-principle" to introduce an emissions trading scheme ▪ Providing a clear message to state-owned electricity generation companies about the government's view that there should be no need for new base-load fossil fuel generation for the next ten years ▪ Considering regulatory options under the Electricity Act 1992 for limiting new base-load fossil fuel generation over the next ten years ▪ Developing a national policy statement for renewable energy in 2008 ▪ Providing greater guidance on "call-in" under the Resource Management Act
Using energy more efficiently	▪ Implemented through the NZEECS (described in the next sub section
Sustainable energy technologies and innovation	▪ Introducing tax credits for research and development expenditure ▪ Providing a contestable fund of $8 million over four years for the deployment of marine generation devices in New Zealand ▪ Establishing a contestable fund of $12 million over three years to support new low-carbon energy technologies
Affordability and wellbeing	▪ Amending regulations for the low fixed tariff option for domestic electricity consumers to take into account regional climate variations that impact on heating costs ▪ Considering the provision of assistance for households to adjust to higher electricity prices arising from the introduction of emissions trading ▪ Supporting the provision of high-quality energy information to householders

In November 2008, the New Zealand governing political party changed from the Labour Party to the National Party. The approach and attitude of the government on natural resources have changed drastically since then. The current government released the “NZES 2011-2021 – Developing our Energy Potential” in August 2011 (Ministry of Economic Development New Zealand 2011). Among the changes in approach is that the current government wishes to explore more untapped local natural resources. In the foreword of the updated NZES, the Minister of Energy and Resources, Hon. Gerry Brownlee stated:

“What is less well known is that along with our renewable resources, we also have an abundance of petroleum and mineral resources. More than 1.2 million square kilometres of our exclusive economic zone are likely to be underlain by sedimentary basins thick enough to generate petroleum. Recent reports put New Zealand's mineral and coal endowment in the hundreds of billions of dollars. For too long now we have not made the most of the wealth hidden in our hills, under the ground, and in our oceans. It is a priority of this government to responsibly develop those resources.”

The current government's goal is for the energy sector to maximise its contribution to economic growth. Hence, to achieve that, the NZES 2010 has set four priorities areas:

i. Diverse resource development
ii. Environmental responsibility
iii. Efficient use of energy
iv. Secure and affordable energy

The update has been taken into account by the EC in preparing the SOO2010 (Electricity Commission 2010) but since the SD model in this research uses the SOO2008, the SOO2010 will not be discussed in detail in this thesis.

5.14.2 National Energy Efficiency and Conservation Strategy (NZEECS)

The strategy's purpose was *"to give effect to the government's policy on the promotion in New Zealand of energy efficiency, energy conservation and the use of renewable sources of energy"*. It is an action plan for many of the programmes in the NZES, and its programmes are complementary to the Emissions Trading Scheme in achieving emissions reductions. The NZEECS targets actions in areas such as homes, businesses, transport and electricity systems.

As required by the Act, the NZEECS has to be revised every 5 years and hence the NZEECS 2007 was released to replace the NZEECS 2001. It was launched alongside the NZES 2007. It provides an action plan to promote sustainability as part of New Zealand's national identity, improve the quality of life for New Zealand families and drive economic transformation in business. The NZEECS 2007's two main non-binding targets are a 20% energy efficiency improvement and an increase of 30 PJ (0.7 Mtoe) per year of renewable energy, both by 2012 (International Energy Agency 2006).

With the NZES draft being released in July 2010, the NZEECS 2010 draft was also released to support the updated strategy. In the NZEECS 2010, the government's proposed energy efficiency target is for the NZEECS to deliver 55 PJ of saving across the economy by 2015 (Ministry of Economic Development New Zealand 2010).

5.15 Resource Management Act

Another important regulation that has a big impact in power system development is the Resource Management Act 1991 (RMA). Most development in New Zealand, including in the energy sector, involves the RMA. It was enacted in 1991 and has since become the most dominant and important piece of environmental legislation in New Zealand. Its objective is to ensure sustainability in managing the country's resources and plan for the future of the environment. In keeping with restructuring in the energy sector, the RMA aims to decentralise decision making and empower territorial and regional authorities to take control of activities within their locality (Pedley 2007).

The overriding purpose of the Act is to promote the sustainable management of natural and physical resources (Ministry for the Environment 1991). The definition of sustainable management is provided in section 5(2) which states: "In this Act, sustainable management means managing the use, development, and protection of natural and physical resources in a way, or at a rate, which enables people and communities to provide for their social, economic, and cultural wellbeing and for their health and safety while

- sustaining the potential of natural and physical resources (excluding minerals) to meet the reasonably foreseeable needs of future generations; and
- safeguarding the life-supporting capacity of air, water, soil, and ecosystems; and
- avoiding, remedying, or mitigating any adverse effects of activities on the environment

The government bodies involved in looking after the environment are the Ministry for the Environment and the Department of Conservation. The Ministry for the Environment gives advice to the government on environmental issues and helps the Minister for the

Environment keep an eye on the way councils do their jobs under the RMA. The Department of Conservation and the Minister of Conservation have a particular role under the RMA to help protect New Zealand's natural and historic heritage.

Local councils have one of the biggest jobs under the RMA. There are three types of councils in New Zealand (Ministry for the Environment 2006) as shown in Table 5.3.

Table 5.3: Different kind of local authorities involved in RMA

Council type	Quantity (throughout New Zealand)	Role
Regional councils	12	Manage the rivers, the air, the coast, the soil and resources that are not generally owned by individuals
City or district councils	69	Monitor land usage that can affect the environment e.g. new subdivisions and land development; plans to clear native bush, change historic buildings, or anything else that might affect what the community has agreed to be important
Unitary authorities	5	Authorities which do the jobs of both regional and district councils

Most areas in New Zealand have both regional councils and city/district councils except for Wanganui, Tasman, Marlborough, Nelson and Timaru, which have unitary authorities. The RMA structure is shown in Figure 5.10. The RMA implementation means that any new development in the energy sector requires the application of resource consents from regional, district and city councils or the Department of Conservation.

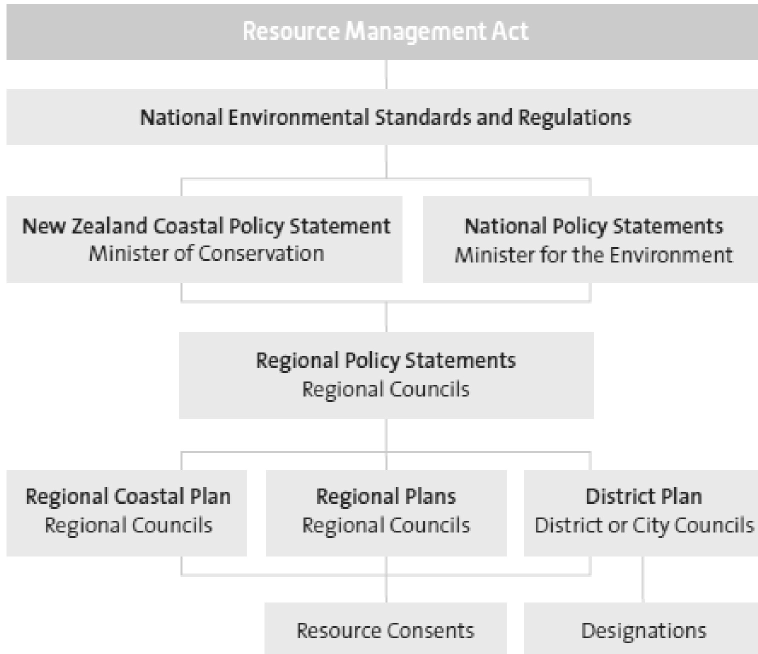


Figure 5.10: RMA structure (Ministry for the Environment 2006)

The different types of resource consents are listed in Table 5.4, along with the consent authorities responsible for issuing them, and examples of when resource consents might be required.

Table 5.4: Consent types and the consent authorities involved (Ministry for the Environment 2006)

Consent type	Consent authority responsible	Examples
Land use consent	Regional councils and/or district and city councils	To construct a building
Subdivision consent	District and city councils	To divide a property into two or more new titles
Coastal permit	Regional councils	To discharge storm water into coastal waters
Water permit	Regional councils	To take water from a stream of an irrigation scheme; to build a dam in the bed of a river
Discharge permit	Regional councils	To discharge storm water directly into a lake; to discharge exhaust fumes into the air

An important principle that underlies the RMA is that those whose activities have the potential to adversely affect the environment should bear the costs of avoiding, remedying or mitigating the consequences of their actions. This principle has significant practical implications for the energy sector and any development proposal that may be put forward. The two main ways in which the RMA ensures adherence to this principle is through rules in regional and district plans, and via the resource consent process.

The introduction of the RMA triggered various responses and criticism. Some view it as a hindrance to development as potential projects can easily be opposed by environmentalists and the general public whose common attitude is ‘Not in my back yard’. While there are time limit guidelines for decisions from the Rulings Panel of the Environment Court under the Resource Management Act, these time limits are not mandatory. This introduces uncertainty as to when a hearing will be scheduled or a decision rendered. Both of these factors increase uncertainty for companies operating in the energy industry in New Zealand, and could therefore inhibit investment (International Energy Agency 2006).

In relation to the electricity sector, a widely held criticism is that compliance with the provisions and procedures under the RMA causes unnecessary delay and expense. In the majority of circumstances, a proposal to establish a new form of electricity generation will require resource consent. In order to obtain this consent, a significant amount of consultation and investigation into potential effects must be carried out. It is frequently commented that these requirements place an unacceptable burden on developers and prevent valuable and otherwise viable projects from taking place. In submissions put forward to the Commerce Commission, the New Zealand Geothermal Association describes the RMA procedures as a major obstacle to further geothermal and wind power developments. They put forward a common criticism, that the up-front costs and delays inherent in the current process make many new developments uneconomic (Pedley 2007).

However, some energy sectors benefitted under the Act. Under section 10 of the RMA, certain existing uses in relation to land are protected. This section allows land to be used in a manner that contravenes a rule in a district plan if the use was lawfully established before the rule became operative or by way of a designation. In both circumstances, the effects of the existing use must be the same or similar in character, intensity and scale to those which existed before the rule became operative or the designation was removed. Transpower frequently utilises these rights to carry out maintenance, repairs and upgrades of its existing power transmission lines and substations.

Although the RMA focuses on empowering local authorities to make decisions, central government still has an important role to play. The RMA provides several methods by which central government may intervene in resource management policy and regulatory decision making that would otherwise be under the jurisdiction of local authorities. The powers of national intervention have recently been modified by the passing of the Resource Management Amendment Act 2005. One of the main focuses of this Act was improving national leadership in the context of the RMA. The amendments attempt to address the difficulties associated with local authorities considering projects of national significance in a policy environment that provides little guidance on how competing national benefits and local costs should be weighed. The national importance of a secure and reliable energy supply makes these amendments particularly relevant to the energy sector (Pedley 2007).

The impact of the RMA in the energy sector has prompted the government to do several amendments such as:

- a 2004 amendment to the RMA to put greater emphasis on the benefits of renewable energy and energy efficiency
- a 2005 amendment to the RMA to improve processes for decision-making on issues of national importance, including energy infrastructure
- a National Policy Statement (NPS) is being developed under the RMA for renewable energy
- developing a NPS on electricity transmission under the RMA

to ensure that the national energy security is not jeopardised by RMA process issues.

5.16 Chapter summary

New Zealand's ESI has undergone several restructuring since late 1980s and is still undergoing some changes. Several dry year shortages had been observed. It is currently unclear how the issue is being addressed especially since the newly formed Electricity Authority is not even made responsible for ensuring energy or supply security. With a continually high reliance on hydro resources, the NZEM is potentially susceptible to shortages during future dry winter years.

6 SD MODEL DEVELOPMENT FOR GENERATION EXPANSION IN NEW ZEALAND

This chapter provides a detailed description of the SD model that has been developed to study the generation expansion in New Zealand. It then explains how the model has been validated using past data.

6.1 Model components

Figure 6.1 shows the three main components of the model – power plant development loop, investment decision loop and the market–investment interaction loop. The full model is shown in Appendix F.

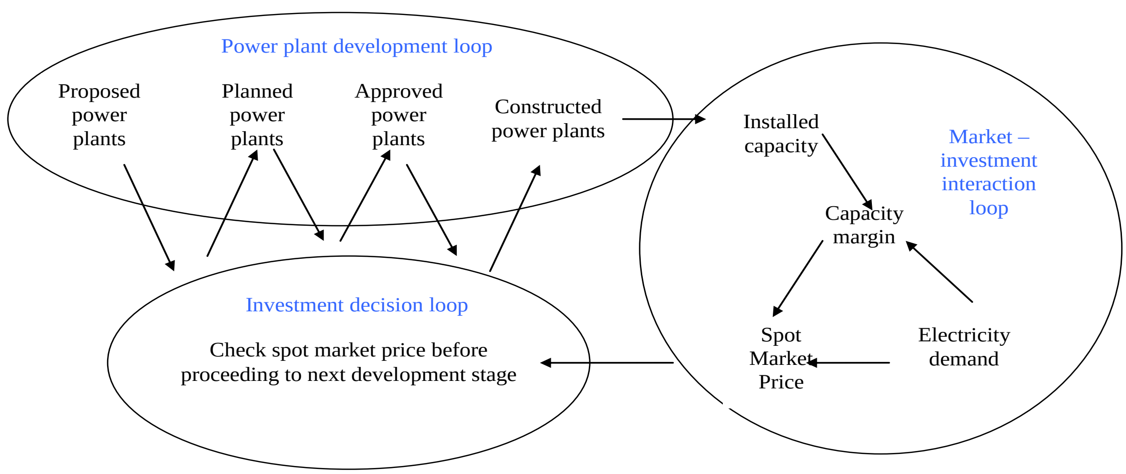


Figure 6.1: Main components of the SD model

6.1.1 Power plant development loop

The 'Power plant development loop' accounts for the different plant types in New Zealand. The plant types are hydro, coal, integrated gasification combined cycle (IGCC), combined cycle gas turbine (CCGT), open cycle gas turbine (OCGT), wind, geothermal, cogeneration, pumped storage and wave. Pumped storage, IGCC and wave plants are currently not available in New Zealand but are introduced in some of the projected future scenarios in the SOO2008 (Electricity Commission 2008).

There are four main phases in the development loop which are:

- proposal
- planning
- approval
- construction

Table 6.1 shows the plant development phase durations that were used in the model. The base values are the typical values in a simulation run. If all the base values for the various phases are added up, they are equal to the plant lead time. Under delay conditions, the values are allowed to vary within the ranges given in the 'Medium delay' and 'Long delay' columns in Table 6.1. These values were obtained by enquiries made from experienced people in the

New Zealand industry as well as referring to some literature (Ford 1999; Meridian Energy 2006).

Base values provide the fastest time a plant can come on line. The allocated base times may seem short, but they cater for plants with small capacities which are more common under a deregulated market environment. However, in most cases, plants take longer than the allocated base times to be ready for commissioning. Hence the model can also be run with medium and long delays as shown in Table 6.1. Due to the long development duration for a power plant, delays are likely to occur for many reasons, depending on the size, type and location of the plants concerned.

Table 6.1: Plant development phase durations and modelled delays

Plant type	Plant lead time (year)			Planning duration (year)			Approval duration (year)			Construction duration (year)		
	Base	Medium delay	Long delay	Base	Medium delay	Long delay	Base	Medium delay	Long delay	Base	Medium delay	Long delay
Hydro	5	7.5	10	1	2	3	1	1.5	2	3	4	5
Coal/IGCC	4	5.5	7	1	1.5	2	1	1.5	2	2	2.5	3
CCGT	3	5.5	7	0.5	1.5	2	0.5	1.5	2	2	2.5	3
OCGT	2	5	7	0.5	1.5	2	0.5	1.5	2	1	2	3
Wind	3	5.5	8	1	2	3	1	1.5	2	1	2	3
Geothermal	3	5.5	8	1	2	3	1	1.5	2	1	2	3
Cogeneration	3	5	7	1	2	3	1	1.5	2	1	1.5	2
Pumped storage	8	10.5	13	1	2	3	2	2.5	3	5	6	7
Wave	5	6.5	8	1	1.5	2	1	1.5	2	3	3.5	4

6.1.1.1 Proposal phase

A power plant's development starts from the proposal phase where the project site is identified and feasibility studies are done. Renewable energy plants might take a longer time to study as it is important to obtain some historical data on the natural resource that is wished to be tapped. If weather data are not readily available from the meteorological departments, they may have to be recorded locally at site.

The model allocates a year for the proposal phase and allows for variations of up to 3 years. Gas plants are given only 6 months as they are mainly concerned with location constraints and do not have to take into account the natural resources to be tapped.

The cost benefit analyses for the proposed plants are also determined in this phase. At the end of the proposal phase, the generation companies should have a list of power stations for consideration. The generation companies will most probably rank the possible plants according to their long range marginal cost (LRMC) and they are most likely to build the cheapest plant, or the one that is likely to give the highest return, first.

6.1.1.2 Planning phase

Once a plant is proposed, the planning phase is for the technical plans to be drafted up. Since this stage usually requires external expertise from consultants, there is a substantial cost involved. For this reason, the model checks the spot market price before taking the plants from the proposal phase to the planning phase. At the end of the planning stage, the generator companies would have the plants ready to be approved. As shown in Table 6.1, renewable energy plants take longer to plan as there is extra planning required to manage the renewable resources. For wave plants, a longer planning duration is allocated given that it is a new type of technology in New Zealand requiring a longer learning curve. In the model, once plants are planned, the generator companies will wait for the right market price before proceeding into the approval phase.

6.1.1.3 Approval phase

The approval phase involves technical approval as well as seeking the resource consents that are made compulsory under the Resource Management Act (RMA), as discussed in section 5.15. The RMA may cause a substantial delay in the development phase if the initial resource consent application is not successful and the generator companies have to appeal the decision. If the appeal involves a substantial litigation cost and drags on for a long time, the plant can be cancelled from being constructed. An example of a project that was cancelled after a long approval process was Project Aqua (Pedley 2003).

The approval time allocated for a gas power plant is shorter (6 months) since it is perceived as clean and usually does not receive much public opposition as compared to plants using other resources. Except for wave and pumped storage, other plants are allocated one year for the approval phase. Hydro plants may be opposed due to the fact that some areas will be submerged to provide for lake storage. Pumped storage is allocated a longer approval time of 2 years because two lakes are required rather than one. Even run of river hydro plants have longer approval times compared to thermal plants because water consents need to be applied for under Section 14 of the RMA (Ministry for the Environment 2006; Environment Canterbury 2010). The consent is required for damming, diverting, taking or using natural water, whether underground water or surface water. This also includes the extraction of heat from geothermal water. Wind power plants are not popular with local people as wind farms are considered unsightly and noisy. Wave power plants are allocated 1.5 years because given that they are a new technology, a longer mitigation process might take place as there is no precedence in New Zealand. Once plants are approved, they are ready for construction.

6.1.1.4 Construction phase

The construction phase is the longest phase within the plant development phase. It may take longer to construct plants in remote areas where access roads and transmission lines will also need to be constructed. These are usually the case for renewable energy plants like wind and hydro. Pumped storage takes even longer as two reservoirs are required. Thermal power plants for coal and CCGT plants take longer to build rather than OCGT plants due to the steam boiler installation. Wave plants are allocated a minimum of 2 years for construction because wave power is a new technology in New Zealand and it might encounter some challenges due to a lack of experience with it.

Once the construction phase is complete, the plants are commissioned and their installed capacities are added to the national installed capacity. These plants will then exit the plant development loop and will be included in the market-investment interaction loop.

6.1.2 Market-investment interaction loop

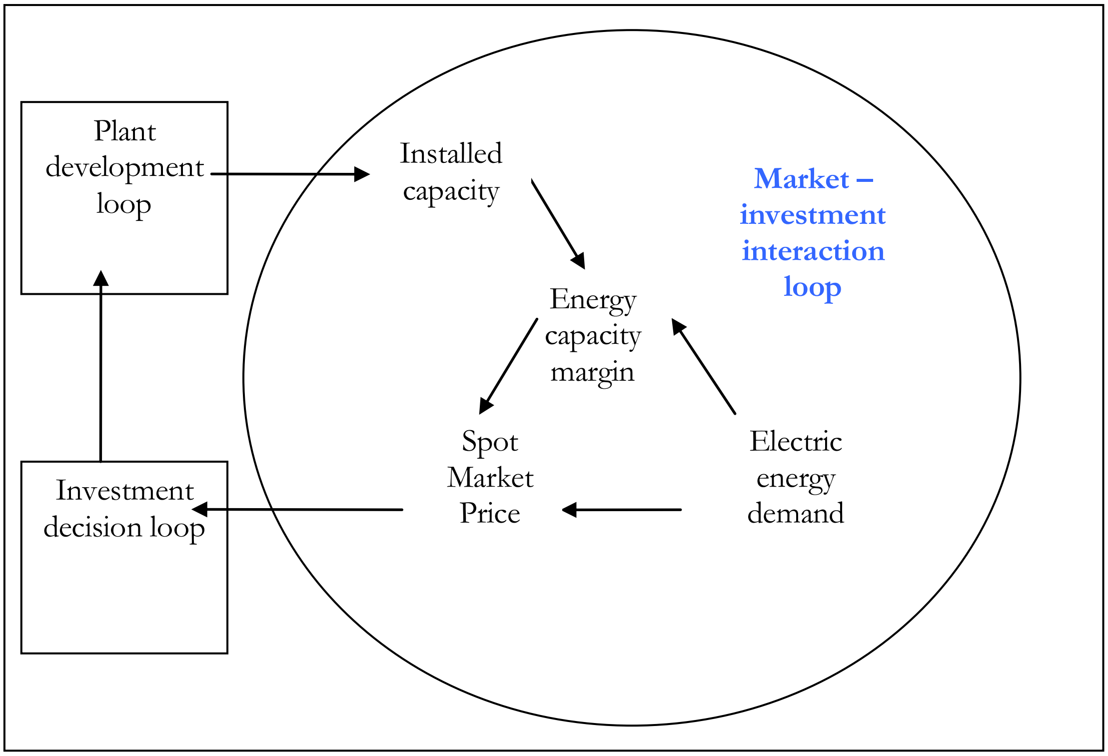


Figure 6.2: Market–investment interaction loop

The market-investment loop shown in Figure 6.2 captures the market mechanism that takes place in New Zealand. The commissioned plants from the plant development loop add to the existing total installed generation capacity. This increases the country's available electric energy supply to meet the demand. The difference between available energy supply and the electricity demand influences the spot market price.

A small difference between the supply and demand gives rise to a higher spot market price. This is usually the case during winter when the electricity demand is higher due to space heating. The price can also go exceptionally high during dry winters. This is because hydro accounts for about 60% of the generation mix in New Zealand and the lack of rainfall will call for the need to use expensive thermal plants instead to meet the demand. Conversely, lower summer demands give rise to larger differences between supply and demand, and the spot market price is expected to fall.

Once a plant gets installed at the end of the plant development loop, the total installed capacity increases. If the added capacity is more than the demand increment, the difference between supply and demand increases. This reduces the spot market price. The price remains low until the difference between supply and demand becomes tight again. This happens when some old plants get decommissioned or the demand increases. It may take years for this to happen.

A new investment occurs when a scheduled power plant gets through from a proposal or planning phase into the next phase. Given that all power plants take a long time to be approved and constructed, it will take several years for the new plants to come on line and add to the total installed generation capacity.

6.1.3 Investment Decision Loop

Without any coordinated planning in place, the only signal for investment under the current market mechanism in New Zealand is a high spot market price that is sustained for a certain long period. In this model, a monthly moving average spot market price is used to trigger new investment. When the price exceeds a plant long range marginal cost (LRMC), the plant will be moved from the proposal phase to the planning phase of the plant development loop. During the time that lapses between each plant development phase, the spot market price may change within the period. Hence the model checks the spot market price again before allowing the planned power plants to proceed into the approval phase. If the market conditions are not conducive at that point in time, the plants are delayed until the spot market price is high enough to provide profits. A similar process is applied before moving a plant into the construction phase. This decision process is illustrated in Figure 6.3.

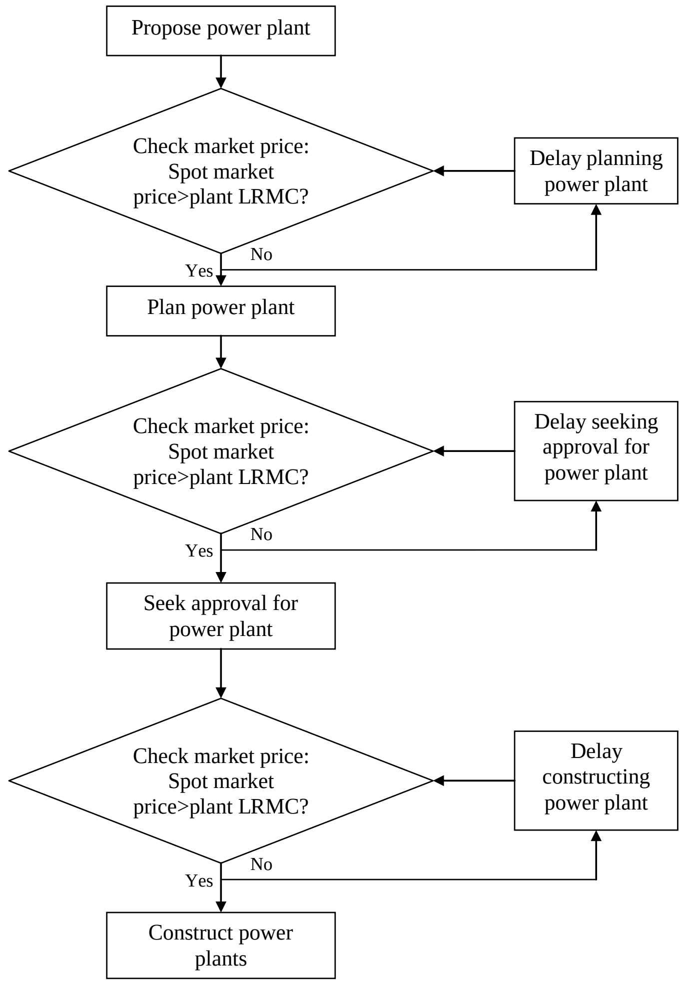


Figure 6.3: Investment decision process used by the SD model

Given that there are several generator companies in New Zealand, it is likely that plants from other companies will come on line while a generator company is developing a plant. This may cause a delay in the plant coming online. For example, generator company X is developing a hydro plant A from 2010. Generator company Y also develops a CCGT plant B from 2010. It is assumed that the spot market price is high enough to allow both plants to proceed into their planning and approval phases. However, plant A faces some public opposition and takes longer to get approved. Hence, when plant B is commissioned, plant A is still seeking approval. When plant B gets commissioned, the installed capacity is higher and the spot market price becomes lower. By the time plant A gets approved, Generator company X might find that the new market price is no longer conducive for them to construct it and decides to delay the construction until the price is up again.

This model considers the market to be conducive for new investments when the spot market monthly moving average price is higher than the plant's LRMC. When this happens, all the plants that are waiting to be moved from one phase to another will be allowed to proceed.

6.2 Model Outputs

There are 3 main outputs that can be obtained from the model. They are:

a) Installed capacity
b) Capacity margin (CM)
c) Energy capacity margin (ECM)

6.2.1 *Installed capacity*

The total installed capacity is the amount of real power (MW) of all generators. It is obtained by summing the resultant installed capacities from each plant development loop:

Total installed capacity = $\sum$ Installed plant capacity (hydro, coal, IGCC, CCGT, OCGT, wind, geothermal, cogeneration, pumped storage and wave)

Equation 1

6.2.2 *Capacity margin*

The capacity margin is defined by

$$\text{Capacity Margin (CM)} = \frac{\text{Total installed capacity - Peak electricity demand}}{\text{Peak electricity demand}}$$

Equation 2

It is a measure of the electricity system's ability to meet the peak demand. The CM is usually expressed in terms of a ratio or percentage.

6.2.3 *Energy capacity margin*

New Zealand has faced problems in meeting energy demands during dry winter years. This has happened in 1992, 2001, 2003 and 2008 (Ministry of Economic Development New Zealand 2009). To enable the model to measure the system's ability to meet the energy demand in any one year, the following term is introduced:

$$\text{Energy Capacity Margin (ECM)} = \frac{\text{Total available electric energy - Electric energy demand}}{\text{Electric energy demand}}$$

Equation 3

The available electric energy (MWh) for a plant for one year is calculated as:

Available electric energy = Installed capacity <plant type> * <plant type> availability factor*8760

Equation 4

The total available electric energy is then taken by summing up all the energy available from each plant type:

Total available electric energy = ∑ Available electric energy (hydro, coal, IGCC, CCGT, OCGT, wind, geothermal, cogeneration, pumped storage and wave)

Equation 5

6.3 Model validation

Before the model was used to provide future projections, it was necessary to validate the model using historical data. The applicable data used for the validation were those recorded after the power market started in New Zealand in October 2006. These data were used in the validation process to provide initial conditions to the model as well as driving the model forward until the year 2009. The results were then compared to the actual data to provide a measure of fitness for the model. The validation process is discussed in detail in the following sections.

6.3.1 Input data

In the model verification stage, several exogenous variables were used to drive the model. They were:

(i) Electricity demand data
(ii) Spot market price
(iii) Installed/Scheduled power plants
(iv) Power plants' LRMC
(v) Power plants' availability factors

These data were fed into the model using Excel files and the Vensim equation editor.

6.3.1.1 Electricity demand data

The electricity demand data used in the model verification stage were the actual monthly consumption data recorded from January 1997 till December 2009 for all of New Zealand. The data was fed into the model to allow the calculation of outputs such as CM and ECM, as shown in Equation 3 and Equation 4.

Monthly electricity consumptions vary throughout the year. Typically, the winter (May-August) consumptions are high due to space heating, whereas consumptions are low around the end of December and early January due to Christmas holidays (when shops and companies close). The data is plotted in Figure 6.4. These data were obtained from the Electricity Commission from their Centralised Database web interface (Electricity Commission 2010). They are listed in tabular form in Appendix B1.

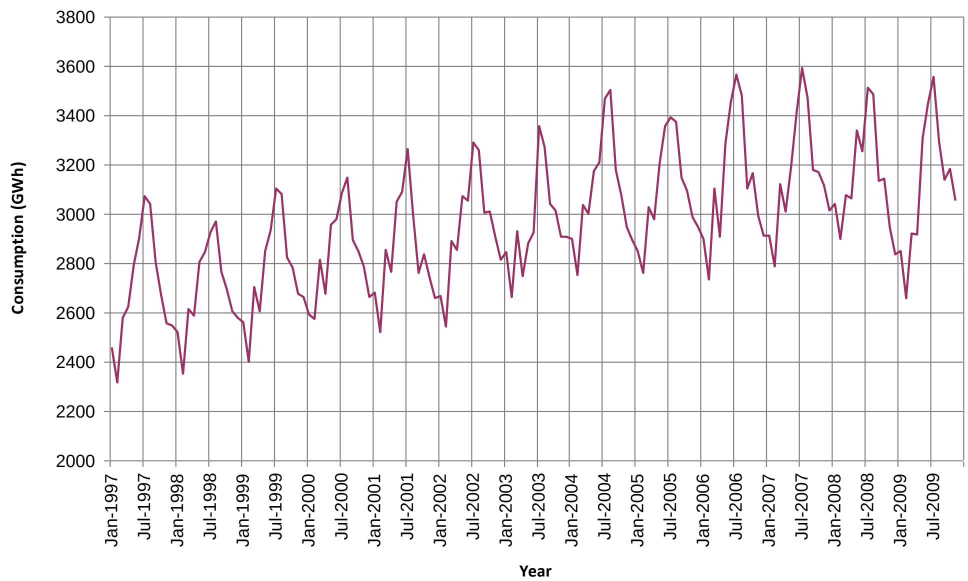


Figure 6.4: New Zealand monthly consumption data from January 1997 to December 2009, used in the model verification stage

6.3.1.2 Spot market price

The spot market prices were taken from the Marketplace Company (MCo) online database called COMIT (MCo 2010). The prices obtained were the monthly prices at three different locations: Haywards, Otahuhu and Benmore. The prices are shown in Appendix B2. Since this model was used to study the installed capacity at the national level rather than at the regional level, the spot prices for the three locations were averaged for each month and used to feed into the model. To take inflation into account, the real prices were then calculated. The base year that was used to verify the model was 2006 because the LRMC values used were the values for that year, as made available in the report Options, Choices and Decisions (Meridian Energy 2006).

The annual inflation rates, *f*, that were used are shown in Table 6.2. The data from the year 1996 till 2006 were obtained from the MED's Energy Data File. The file contained values of Consumer Price Index (CPI) from the year 1946 till 2006, using the year 1970 as a base. The CPI values from the year 1996 till 2006 are also included in Table 6.2.

Table 6.2: Annual inflation rate values used in the model verification stage

Year	CPI	Annual Inflation rate (%), *f*
1996	888.38	
1997	898.82	1.17
1998	910.39	1.29
1999	909.26	-0.12
2000	933.08	2.62
2001	957.58	2.63
2002	983.21	2.68
2003	1000.45	1.75
2004	1023.37	2.29
2005	1054.45	3.04
2006	1089.93	3.37
2007		*2.50*
2008		*3.40*
2009		*3.00*

From the given CPI values, the annual inflation rates were calculated using the formula (DeGarmo, Sullivan et al. 1993):

$$(\text{CPI annual inflation rate})_i = \boldsymbol{f_i} = \frac{(CPI)_i - (CPI)_{i-1}}{(CPI)_{i-1}} * (100)$$

Equation 6

The annual inflation rate values for the year 2007 till 2009 were obtained from the New Zealand Inflation Calculator from the Reserve Bank of New Zealand's website (Reserve Bank of New Zealand 2010).

Using the annual inflation rates, *f*, and prices in actual dollars(A$), the real dollars (R$) for any year *i* can then be calculated using 2006 as a base (DeGarmo, Sullivan et al. 1993) using the general formula:

$$(\text{R\$})_i = (\text{A\$})_i \left(\frac{1}{1+f} \right)^{i-2006}$$

Equation 7

The formula was developed with *f* constant each year. For a more realistic calculation where *f* varies each year, the formula is modified to:

$$(\text{R\$})_{\text{i}} = (A\$)\left(\frac{1}{1+f_i} \right) \left(\frac{1}{1+f_{i+1}} \right)$$

for the years after 2006

$$(\text{R\$})_{\text{i}} = (A\$)(1+f)^{i+1}(1+f)$$

for the years before 2006

Equation 8

Based on Equation 8, yearly multipliers were calculated using Equation 9 to ease the monetary values conversion. The calculated multipliers used for the conversion are shown in Table 6.3.

$$(\text{Yearly multiplier})_{\text{i}} = \left(\frac{1}{1+f_i}\right)$$

$$(\text{Effective multiplier})_{\text{i+1}} = \left(\frac{1}{1+f_i}\right)\left(\frac{1}{1+f_{i+1}}\right)$$

Equation 9

Table 6.3: The multipliers used in converting actual prices to real prices with 2006 as the base year

Year	Yearly multiplier	Effective multiplier
1997	1.0117	1.2126
1998	1.0129	1.1972
1999	0.9988	1.1987
2000	1.0262	1.1681
2001	1.0263	1.1382
2002	1.0268	1.1085
2003	1.0175	1.0894
2004	1.0229	1.0650
2005	1.0304	1.0337
2006	1.0337	1.0000
2007	1.0250	0.9756
2008	1.0340	0.9435
2009	1.0300	0.9160

The actual prices and calculated real prices that were used in the model verification are plotted in Figure 6.5. Due to inflation, the calculated real prices before the base year 2006 are higher than the actual prices and vice versa after 2006. For the year 2006, their values are the same since 2006 is the index year.

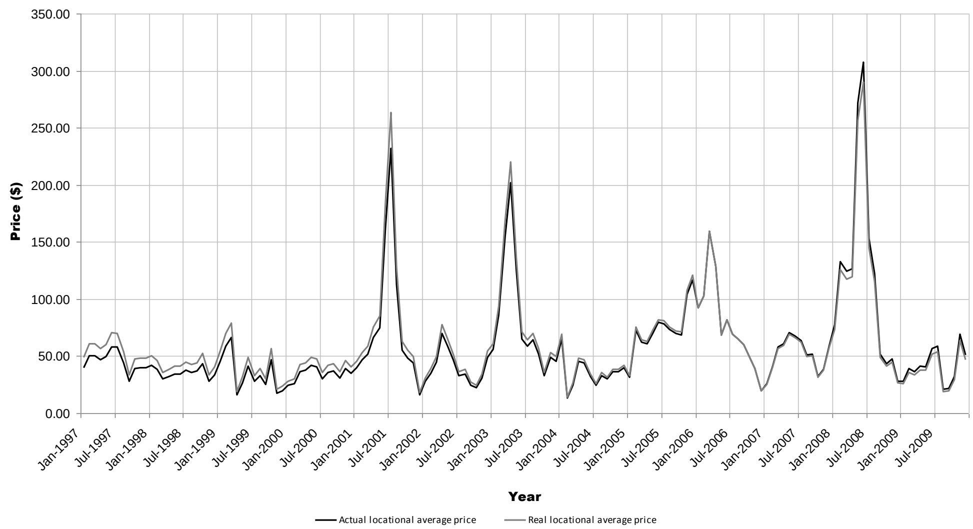


Figure 6.5: Actual and real average prices from January 1997 till December 2009

6.3.1.3 Scheduled power plants

Within the duration 1996 to 2008, several power plants were commissioned as shown in Table 6.4. The list of decommissioned plants during this period is shown in Table 6.5. Modifications and refurbishments within the duration that affected the installed capacity are shown in Table 6.6. The information in the tables had been extracted from the Energy Data File 2009 (Ministry of Economic Development New Zealand 2009) and records from the Electricity

Commission (Electricity Commission 2010). The lists are not exhaustive as plants with lower capacities, especially cogeneration plants, were not accurately recorded. There was also a difficulty in obtaining an accurate record of decommissioned plants.

Due to the data inaccuracy, the input for the model was derived from the net installed generation capacity in New Zealand rather than individual plants. The data is shown in Table 6.7 (Ministry of Economic Development New Zealand 2009). The information is extracted from the 2009 Energy Data File as shown in Appendix B3. The yearly differences were then calculated and shown in the shaded columns. They were net of new installed capacities and decommissioned plants. They also include the updated capacities from refurbished or upgraded plants.

Table 6.4: Power plants commissioned between 1996 and 2008

Plant Name	Plant type	Year Commissioned	Capacity (MW)
Edgecumbe	Gas (Cogeneration)	1996	10
Hau Nui	Wind	1996/	4/8.5
Christchurch City Wastewater	Biogas	1996	3.2
Southdown	CCGT (Cogeneration)	1997/2007	125/175
Whareroa	CCGT (Cogeneration)	1997	68
Rotokawa	Geothermal	1997/2002	16/34
Poihipi	Geothermal	1997/2008	55/75
Kinleith	Biomass/Coal /Gas (Cogeneration)	1998	40
Kapuni	CCGT (Cogeneration)	1998	23
Taranaki	CCGT	1998	385
Ngawha	Geothermal	1998/2008	10/25
Tararua Wind Farm	Wind	1999/2004/2007	31.7/68/161
Otahuhu B	CCGT	2000	380
Te Rapa	Gas (Cogeneration)	2000	44
Blue Mountain Lumber	Cogeneration	2000	1.4
Mokai	Geothermal	2000/2005/2007	18/95/112
Onekaka	Hydro	2002	0.94
Watercare Mangere	Cogeneration	2003	7
Whirinaki	Diesel	2004	155
Huntly U6	OCGT	2004	50
Te Apiti	Wind	2004	91
Auckland District Hospital	Cogeneration	2004	3.6
Pan Pac	Biomass/Coal/Gas (Cogeneration)	2005	13
Huntly U5	CCGT	2007	385
White Hill	Wind	2007	58
Totora Valley	Hydro	2007	2
Kawerau	Geothermal	2008	100
Kawerau – KA24	Geothermal	2008	8.3
DeepStream	Hydro	2008	5
Mangahewa	Gas	2009	9
Te Rere Hau	Wind	2009	30
Matawai	Hydro	2009	2
West Wind	Wind	2009	143

Table 6.5: Power plants decommissioned from 1996 to 2008

Year	Plant name	Plant Type	Decommissioned capacity (MW)
1998	Stratford A	Thermal	110
2003	Otahuhu A	Thermal	45.75
2008	New Plymouth	Thermal	600

Table 6.6: Major plant refurbishment from 1996 to 2008

Year	Plant name	Plant Type	Modification work	Modified capacity (MW)
1997	Glenbrook	Cogeneration - Coal/Gas Waste from steel mill	Added a second plant	+56
1999	Teviot river scheme - Horseshoe Bend	Hydro	Added capacity to the hydro scheme	+4.315
	Opuha	Hydro	Revived after a flood in 1997	+7.5
	Motueka	Hydro	Revival from decommissioning	0.24
2000	Conical Hill	Thermal	Added a steam turbine to a 10MW boiler	+1.4
	Teviot river scheme - George	Hydro	Two 500kW generators replaced by one 1MW	+1
2002	Manapouri	Hydro	A second tailrace tunnel, and up rating of the turbines to 120MW	+120 (585 to 700)
	Falls - Irrigation dam near St. Bathans, Otago	Hydro	Upgrading of an old irrigation dam	+1.25
2003	Mangahao	Hydro	A mini hydro addition	+4
2004	Wairua Falls	Hydro	Added a fourth generator made up of three 1·2MW Francis turbines	+3.6
	Motukawa	Hydro	Added a turbine in the water race to lake Ratipiko	+0.2
2005	Monowai	Hydro	Refurbishment to three 2·6MW turbines	+7.8
	Wairakei	Geothermal	Addition of a low-temperature isopentane system.	+14
2007	Poihipi	Geothermal	Upgraded to provide additional capacity	+40
2008	Manapouri	Hydro	Refurbishment work (starting in 2002)	+30 (700 to 730)

Table 6.7: The net installed generation capacity by plant types from 1996-2008

December	Plant capacity (MW)															
	Hydro	Difference	Geo-thermal	Difference	Wind	Difference	Coal/Gas	Difference	CCGT	Difference	OCGT	Difference	Cogeneration rations	Difference	Total	Difference
1996	5192		276		4		1000		0		1134		**228**		**7834**	
1997	5192	0	373	97	4	0	1000	0	0	0	820	-314	**499**	271	**7888**	55
1998	5192	0	383	10	4	0	1000	0	385	385	472	-348	**499**	0	**7935**	47
1999	5199	7	383	0	36	32	1000	0	385	0	372	-100	**494**	-5	**7869**	-66
2000	5202	3	365	-18	36	0	1000	0	765	380	372	0	**543**	49	**8283**	414
2001	5202	0	365	0	36	0	1000	0	765	0	372	0	**545**	2	**8284**	2
2002	5342	139	365	0	36	0	1000	0	765	0	372	0	**529**	-16	**8409**	125
2003	5348	6	370	5	72	36	1000	0	765	0	372	0	**533**	4	**8460**	51
2004	5345	-3	370	0	166	94	1000	0	765	0	567	195	**539**	6	**8753**	292
2005	5346	1	425	55	168	2	1000	0	765	0	467	-100	**579**	40	**8751**	-2
2006	5346	0	425	0	169	1	1000	0	765	0	477	10	**609**	30	**8792**	40
2007	5349	2	443	18	320	151	1000	0	1150	385	477	0	**656**	48	**9396**	604
2008	5376	27	577	134	322	2	1000	0	1150	0	294	-183	**661**	4	**9380**	-16

Even though the yearly difference in the actual installed capacity shown in this table may be contributed by several plants, the model sees it only as one plant with a total capacity of the sum of the contributing plants. This is reasonable because due to lack of available data, currently the model is not able to analyse each plant by its own property such as its capacity and development duration. It uses an average value for each plant type instead.

6.3.1.4 Power Plant's LRMC

The LRMC values used in the validation process are shown in Table 6.8. They were obtained from the 2006 publication by Meridian Energy (Meridian Energy 2006). No value is required for coal plants during the duration as there was no coal plant proposed.

Table 6.8: LRMC values for different plant types

Plant type	LRMC (NZD/MWh)
Hydro	62
Wind	60
Geothermal	60
OCGT	100
CCGT	70
Cogeneration	50
Coal	N/A

6.3.1.5 Power Plants' Availability Factors

As discussed in Section 6.2.1, one of the useful outputs from the model was the calculation of available energy from the installed capacity in New Zealand. The resultant installed capacity from the plant development loop provided the values to calculate the *potential monthly generation*. The potential generation was calculated based on the plant type availability factors. The factor indicated the annual plant availability to generate electricity when required, as a percentage of its theoretical maximum availability, i.e. all the time. It took into account the energy resource's availability and the annual maintenance and outages. The values that were used in this validation process are shown in Table 6.9. The values were consistent with the values of plants availability factor (termed as “load factors” in SOO2008) used by EC in their SOO2008 analyses (Electricity Commission 2008). It was assumed that from 1996 to 2050, technology does not change so much as to affect a plant’s availability factor.

Table 6.9: Availability factor for each plant type

Plant type	Availability factor
Hydro	0.5
Wind	0.35
Geothermal	0.9
OCGT	0.9
CCGT	0.9
Cogeneration	0.7
Coal	0.9

The potential monthly generation (MW) is calculated as:

Potential monthly generation = installed capacity*availability factor

Equation 10

6.3.2 Model validation steps

There were several items in the model that require validation. They were:

(i) The plant development and investment decision equations
(ii) The price equations
(iii) The overall model validation

The plant development and investment decision equations needed to be verified as they provided the main outputs from the model. The price equation was important because to make future forecasts using the model, there was no market price prediction available to drive the model. Hence, the model needed to derive the market price based on the margin between the electricity supply and demand. Once the two parts had been verified independently, the overall model was then evaluated to ensure that it would yield good and reliable results when used for forecasting. If the SD model was able to replicate the historical trends, it was assumed that its forecasts would be reliable.

Taking these reasons into account, the model validation was undertaken in the following separate progressive stages:

Stage 1

To validate the development phase and investment decision equations, historical prices and consumption data were used as exogenous inputs to drive the model. A power plant development schedule was drafted based on the installed capacity between 1997 and 2008. The resultant installed capacity and the actual installed capacity were then compared. If the model used the correct framework and equations in the plant development and investment decision loop, the resultant installed capacity should not differ much from the actual installed capacity. This work is discussed in Section 6.3.2.1.

Stage 2

To validate the price equation, the historical generation supply (actual installed capacity) and demand data were used as exogenous inputs to the SD model. The resultant price was then compared to the past price to provide a goodness of fit measure.

Stage 3

To evaluate the model's overall effectiveness, the derived price equation and plant schedules were used to drive the model. The resultant installed capacity and price were then compared to the past data to test for goodness of fit.

6.3.2.1 Model validation – development phase and investment decision equations

This validation was done to ensure that the timing allocated for each development phase was reasonable and realistic. It also checked whether the investment decision equations work in providing timely investment, given the right market conditions. The investment decision framework has been discussed in section 6.1.3 and illustrated in Figure 6.3.

The development phases and investment framework were processed by:

- Feeding the model with scheduled capacities subtracted with the base lead time at the planning stage using step functions. Step functions were used because of discrete and lumpy nature of power plant capacities and the plant unit comes on line as a whole rather than in fractions, e.g. after commissioning, a unit of 100MW will have 100MW available from it rather than just 10MW.

- When the market condition was correct (spot market monthly moving average real price>plant type LRMC), the capacities were moved to the next phase. Otherwise, they were delayed (as illustrated in Figure 6.3).

6.3.2.2 Inputs

A power plant schedule was drafted based on the yearly difference of actual installed capacities for different types of plants as shown in Table 6.7. The obtained plant development schedule is shown in Table 6.10. The schedule uses the plant lead time and development duration as shown in Table 6.1. The lead times and development durations for these plants were extracted from the base duration values of Table 6.1.

Table 6.10: Plant schedules for model validation

Plant type	**New plants**			**Retired plants**	
	Start	Year commissioned	Capacity (MW)	Year decommissioned	Capacity (MW)
Hydro	*1994*	*1999*	*7*	2004	-3
	1995	*2000*	*3*		
	1997	2002	139		
	1998	2003	6		
	2000	2005	1		
	2002	2007	2		
	2003	2008	27		
Wind	*1996*	*1999*	*32*	-	-
	2000	2003	36		
	2001	2004	94		
	2002	2005	2		
	2003	2006	1		
	2004	2007	151		
	2005	2008	2		
Geothermal	*1994*	*1997*	*97*	2000	-18
	1995	1998	10		
	2000	2003	5		
	2002	2005	55		
	2004	2007	18		
	2005	2008	134		
Cogeneration	*1994*	*1997*	*271*	1999	-5
	1997	2000	49	2002	-16
	1998	2001	2		
	2000	2003	4		
	2001	2004	6		
	2002	2005	40		
	2003	2006	30		
	2004	2007	48		
	2005	2008	4		
OCGT	2002	2004	195	1997	-314
	2004	2006	10	1998	-348
				1999	-100
				2005	-100
				2008	-183
CCGT	*1995*	*1998*	*385*	-	-
	1997	2000	380		
	2004	2007	385		
Coal	-	-	-	-	-

Years in italics are outside the simulation range but taken into account by the model (refer to following texts).

Table 6.11: Plant base lead time and development duration

Plant type	Plant lead time (year)	Planning duration (year)	Approval duration (year)	Construction duration (year)
Hydro	5	1	1	3
Coal	4	1	1	2
CCGT	3	0.5	0.5	2
OCGT	2	0.5	0.5	1
Wind	3	1	1	1
Geothermal	3	1	1	1
Cogeneration	3	1	1	1

Once the information on plant commissioning and decommissioning wass derived, a starting date for the plant development was obtained by applying the base lead time to the plant. For example, applying the 2 year lead time to an OCGT plant, the first OCGT capacity was fed into the model as a time step of 195MW in the year 2002. If the model correctly captured the market mechanism, this capacity should come on line around the year 2004 as happened historically.

The model validation simulation was run from the year 1997-2009. Some of the capacities were already under development in 1997. The affected capacities are shown in *italics* in Table 6.10. The capacities that came on line in 1997 were fed into the model as step functions effective in 1997. The capacities that came later but were started before the simulation duration, were placed in the respective development phase as shown in Table 6.11. For example, the hydro capacity to be commissioned in 1999 should be under construction in 1994 and hence is fed into the construction phase of the model.

The refurbished plants were treated as new installed plants. This was because a major refurbishment work may take a long time, similar to building a new plant. Since 1991, any refurbishment work must also obtain a resource consent under the Resource Management Act 1991 (RMA) and hence requires an approval stage. It was therefore reasonable to treat refurbishment work as a new plant under the base lead time. An example of such refurbishment is the construction of the second tailrace tunnel at Manapouri. The work started in June 1997 and it was commissioned in 2002 (Meridian Energy 2011). The five year construction duration was the same as the base time allocated for a new hydro power plant development. Ideally, the model can be accurate if the development of each plant is known (when it was proposed, planned, approved and constructed) and fed into the model. However, this data was not publicly available.

To demonstrate how the model captures the framework, Figure 6.6 shows the transition of wind power plants from the proposal to planning phase, whereas Figure 6.7 shows the comparison of the spot market price with wind power plant LRMC. From Figure 6.6, it can be seen that 36MW was proposed in 2000 and 94MW in 2001. These capacities were in agreement with the scheduled capacities shown in Table 6.10. Initially, from Figure 6.7, it is observed that the market price was below the LRMC value. The price was first above the value in early 2001 and hence both the proposed plants were allowed by the model into the planning phase. After a year, the plants would have completed the planning stage and were waiting for the correct market condition to proceed to the approval stage.

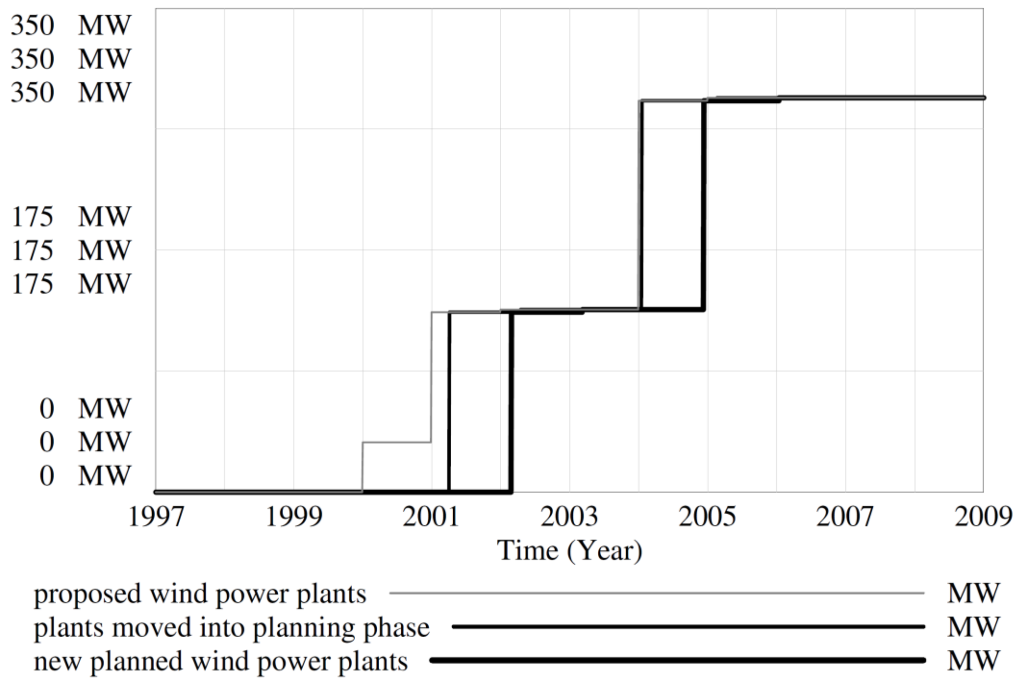


Figure 6.6: Wind power plants phase transition from proposal to planning

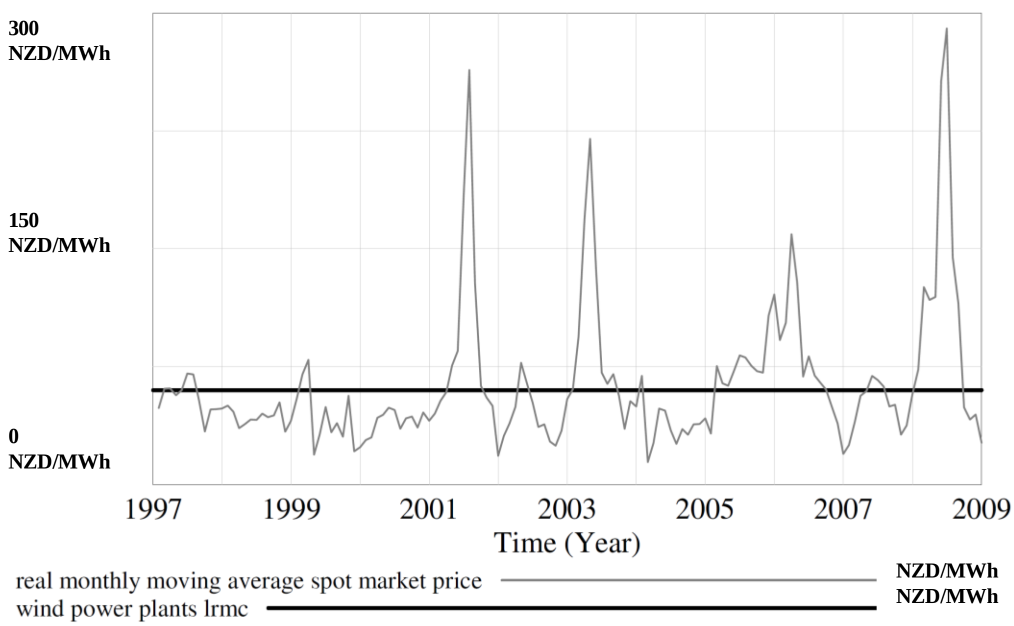


Figure 6.7: The real monthly moving average spot market price compared to the wind power plant LRMC

6.3.2.3 Results

The simulation results for the validation of the development phase and investment decision equations stage are shown in Figure 6.8 to Figure 6.14. As mentioned in Section 6.3.1, the historical real prices and consumption data were used to drive the model. The resultant installed capacity from the SD model is compared to the actual installed capacity shown in Table 6.7).

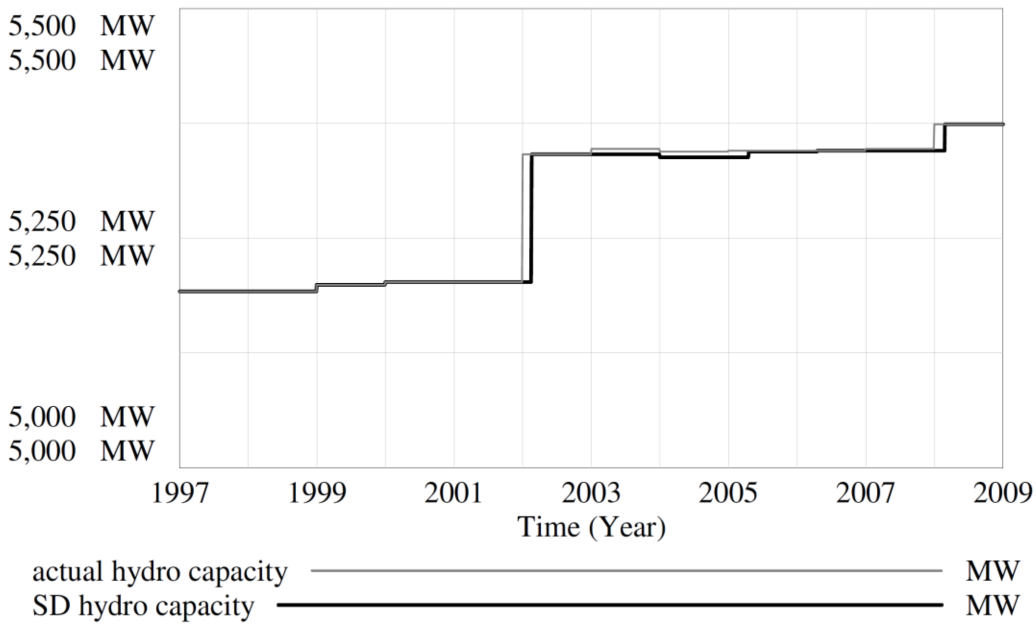


Figure 6.8: Hydro capacity comparison

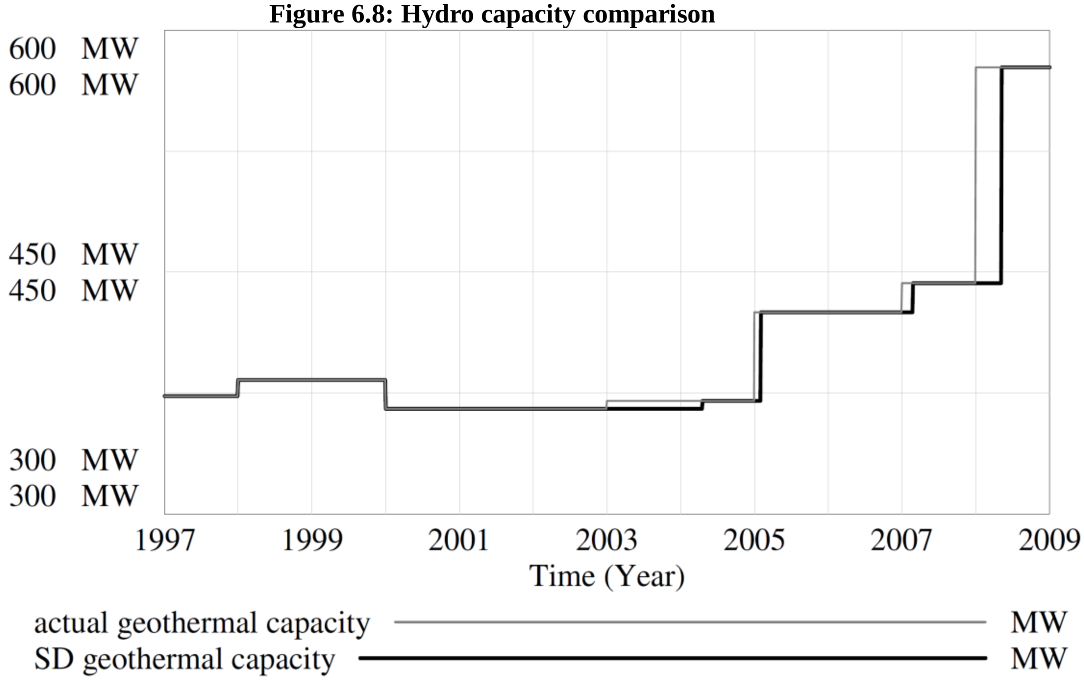


Figure 6.9: Geothermal capacity comparison

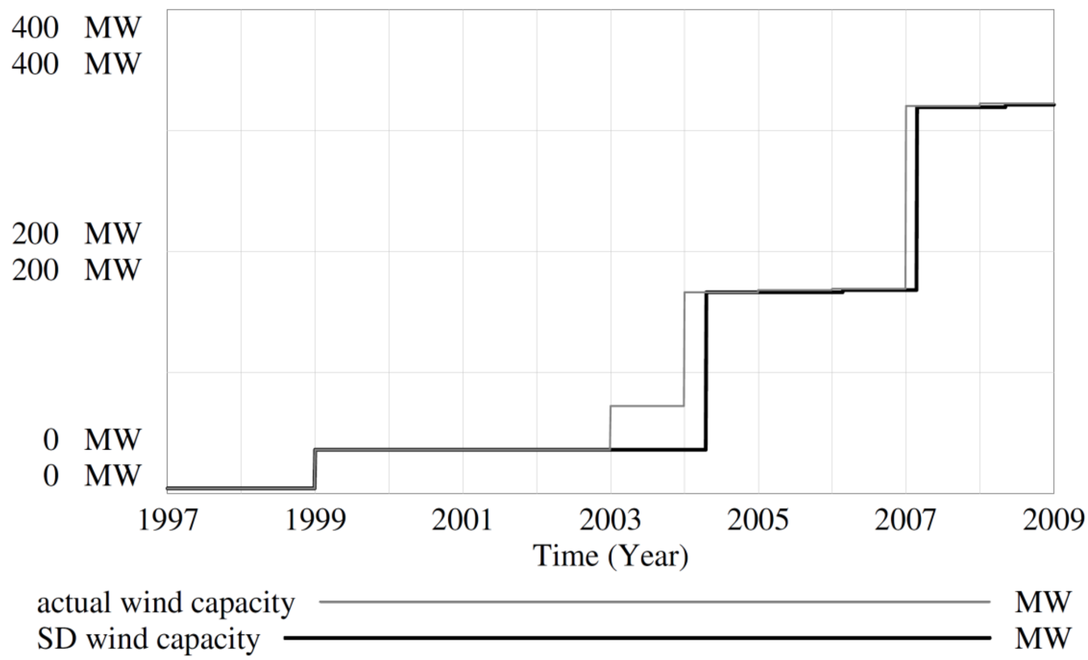


Figure 6.10: Wind capacity comparison

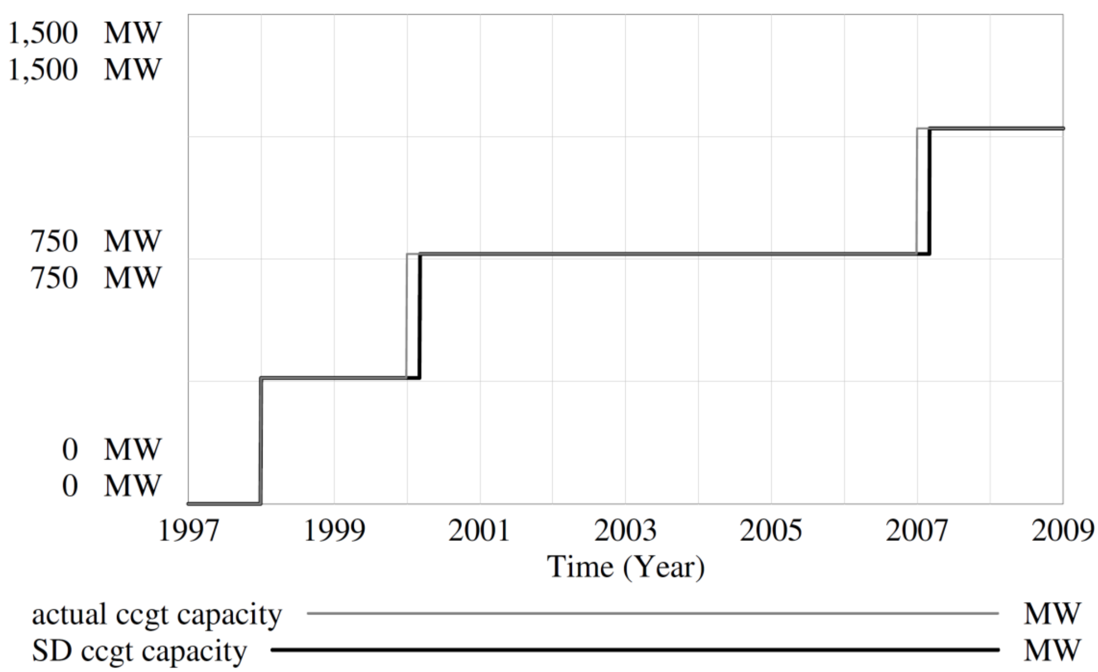


Figure 6.11: CCGT capacity comparison

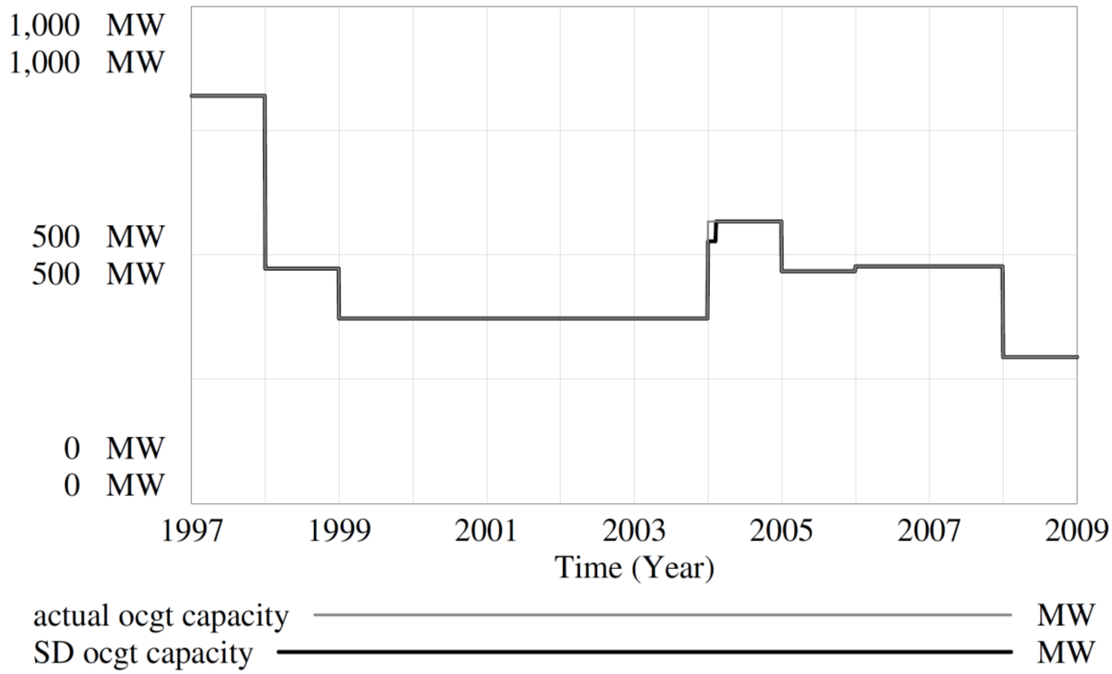


Figure 6.12: OCGT capacity comparison

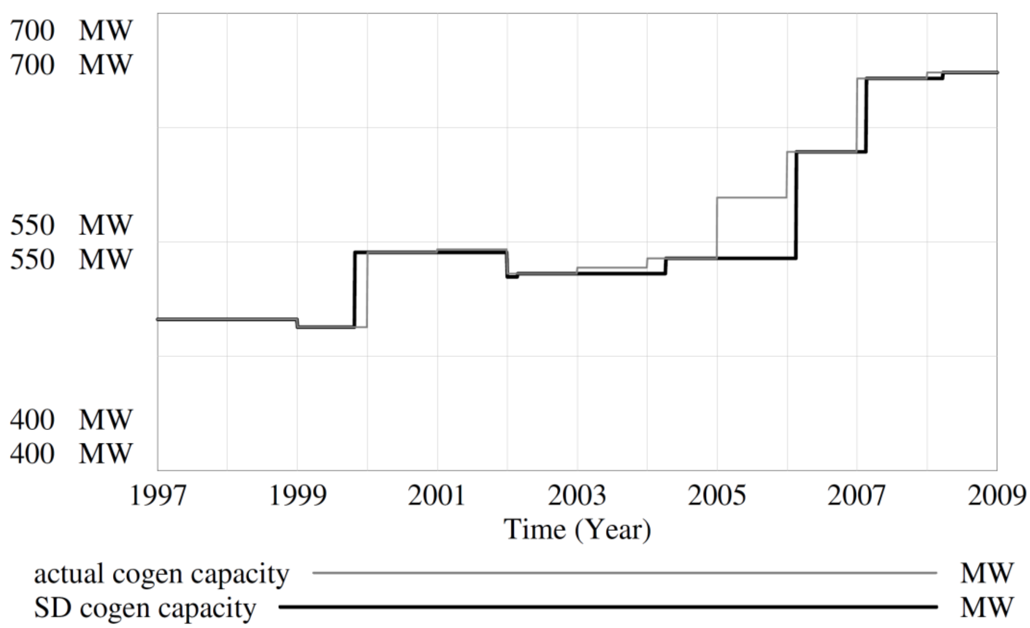


Figure 6.13: Cogeneration capacity comparison

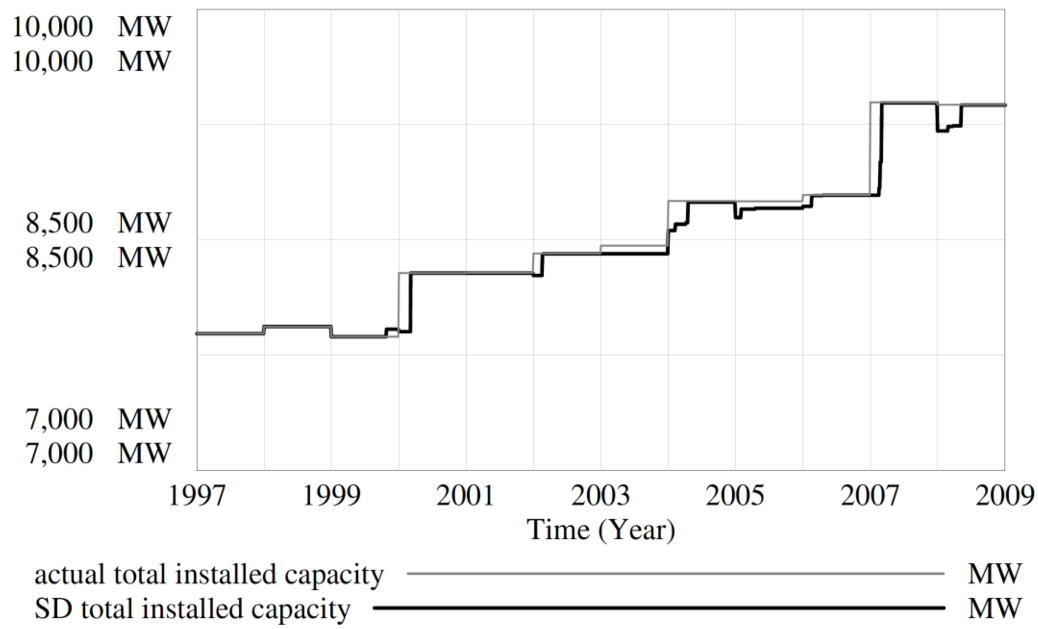


Figure 6.14: Total capacity comparison

All the figures show that the simulated results are close to the actual historical data. Some of the resultant capacities from the SD model appear slightly ahead or later than the actual installed capacities. This is because the actual capacities record is updated annually in December whereas the SD model can update its result at any time according to the model time resolution.

The actual total installed capacity provided by the MED (Ministry of Economic Development New Zealand 2009) was taken at December of each year. Figure 6.15 takes the SD model validation results annually in December and compares it with the MED annual data.

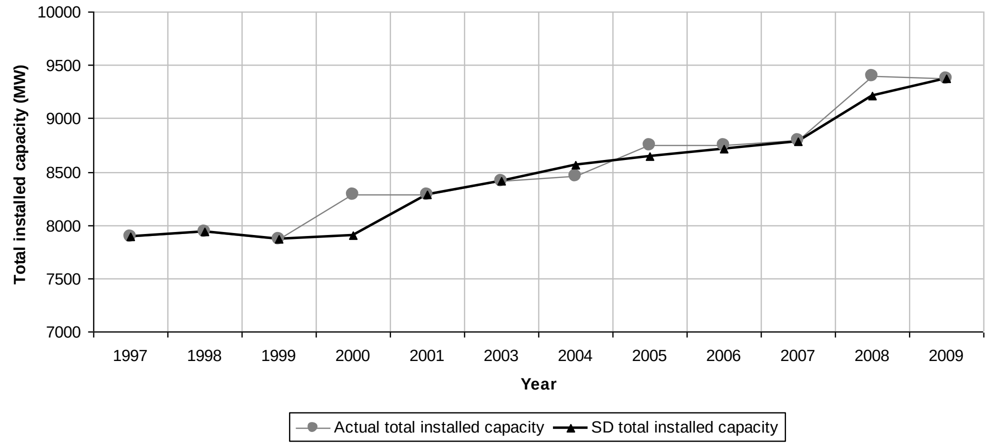


Figure 6.15: Comparison of actual data with the SD model results taken annually

When comparing both results annually in December as shown in Figure 6.15, the SD results were very close to the actual installed capacity. Therefore it can be concluded that the development loop and the market-investment loop in the model worked well in modelling the power market mechanism.

6.3.2.4 Model validation - price equations determination

The model validation results in Section 6.3.2.3 were obtained using historical price (real price) and consumption data. To allow the model to be used in performing future projections, equations must be derived to determine the future spot market prices. This section describes how the price equation is derived and validated.

Theoretically, the spot market prices vary depending on the differences between the amounts of supply and demand. Realistically, the prices are also affected by transmission congestions. In New Zealand, the spot market prices in the north and south islands decouple and vary significantly when the HVDC link connecting the two islands is down. This model only used the supply and demand differences in formulating the spot market prices. Figure 6.16 shows the spot market price determination loop. The loop was used to calculate the monthly average prices.

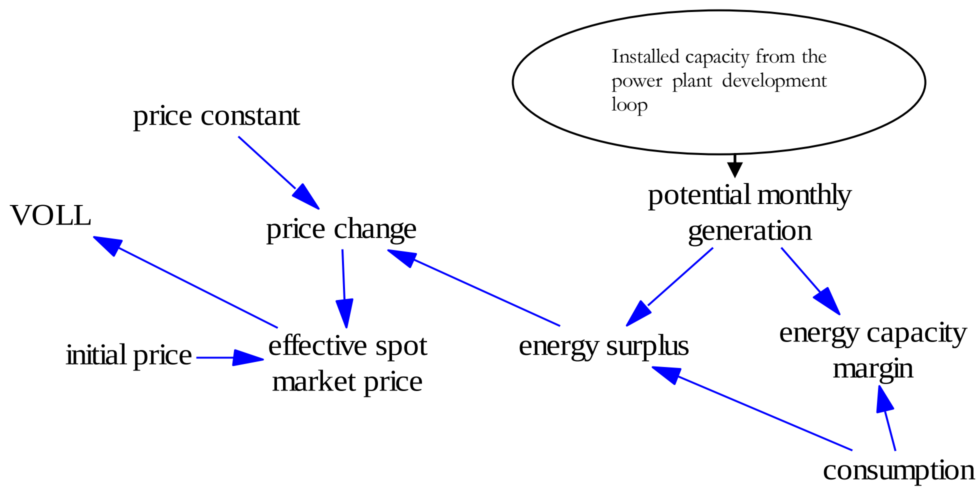


Figure 6.16: Spot market price determination loop

The monthly consumption data is also used to allow the calculation of *energy capacity margin* and *energy surplus*. The *energy surplus* is defined as the difference between the *potential monthly generation* and the *consumption* (monthly). The *energy surplus* then causes the price to respond accordingly where a small surplus will result in a higher spot market price and vice versa. The *price constant* is a proportionality constant that affects how much the *price change* variable responds to the *energy surplus*.

Since the price is inversely proportional to the *energy surplus*, it is then defined as:

$$Price\ change = (price\ constant) / (energy\ surplus)$$

Equation 11

As described in section 6.2.3, the ECM is defined as the ratio of the energy surplus and demand:

$$Energy\ capacity\ margin = (Energy\ surplus) / (Consumption)$$

Equation 12

As defined in Equation 3, the *Energy Surplus* is calculated as the difference between the total available electric energy and the electric energy demand. Another constant that is used in determining the spot market price is the initial price. The initial price is the monthly average market price at the start of the simulation. Any subsequent price is known as the effective spot market price and is defined as:

$$Effective\ spot\ market\ price = (Initial\ price) + (price\ change)$$

Equation 13

The effective spot market price can be very high if the margin between energy supply and demand is very small. Hence the variable is capped to the Value of Loss Load (VOLL) for the electricity industry in New Zealand, as theoretically implied in market theory (Stoft 2002). The VOLL value has been determined by the New Zealand Centre for Advanced Engineering (Centre for Advanced Engineering 2004) to be NZD20.95/MWh.

Since the price is dependent upon the margin between energy supply and demand, the following steps were taken in determining the price constant in the price loop:

- Using past generation supply availability data to calculate the energy surplus
- Using past hydrological data to take into account hydro shortages in dry winters
- The hydrological data is a useful input because hydro accounts for 60% of New Zealand's generation mix.

6.3.2.5 Inputs

Figure 6.17 shows the electricity generation and consumption data from 2003 to 2010. The figure was plotted based on the records held by EC (Electricity Commission 2008). The monthly generation data is tabulated in Appendix B4. The detailed electricity generation prior to 2003 is not available. It is shown that the generation is always more than the consumption due to losses in delivering the energy from the power plants to the consumers. However, the generation trends follow the consumption trends because the energy has to be supplied instantaneously to meet demand, since electricity cannot be stored. The consumption data that was used in this stage is the same as the previous stage (Section 6.3.2.2).

The actual supply generation mix within the duration is shown in Figure 6.18. The figure was plotted based on MED records (Ministry of Economic Development New Zealand 2008). It can be seen that geothermal plants mainly served as a base load. Generally, CCGT and coal plants also work as base load, whereas OCGT and diesel work as peakers. Hydro and wind generation varied with respect to weather conditions.

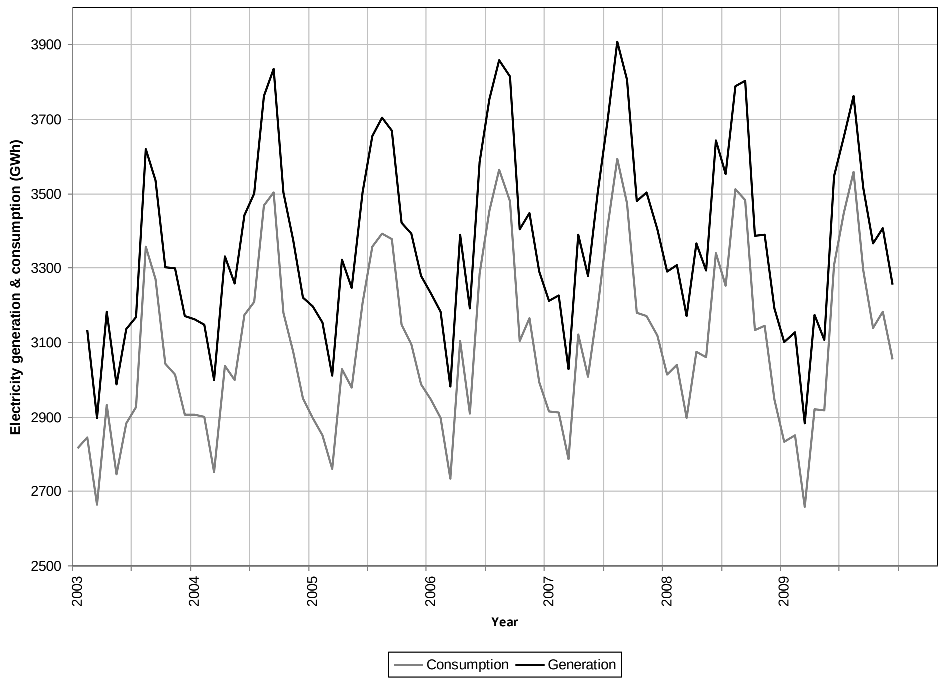


Figure 6.17: Electricity generation and consumption from 2003 to 2010 (plotted based on data from EC (ref))

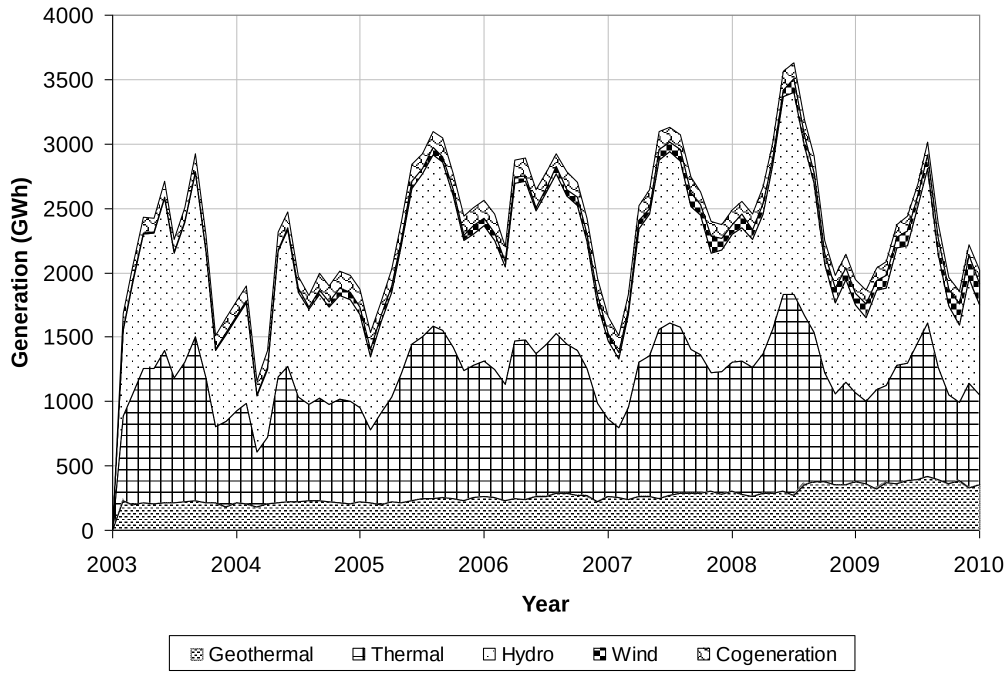


Figure 6.18: Main generation mix from 2003 to 2010

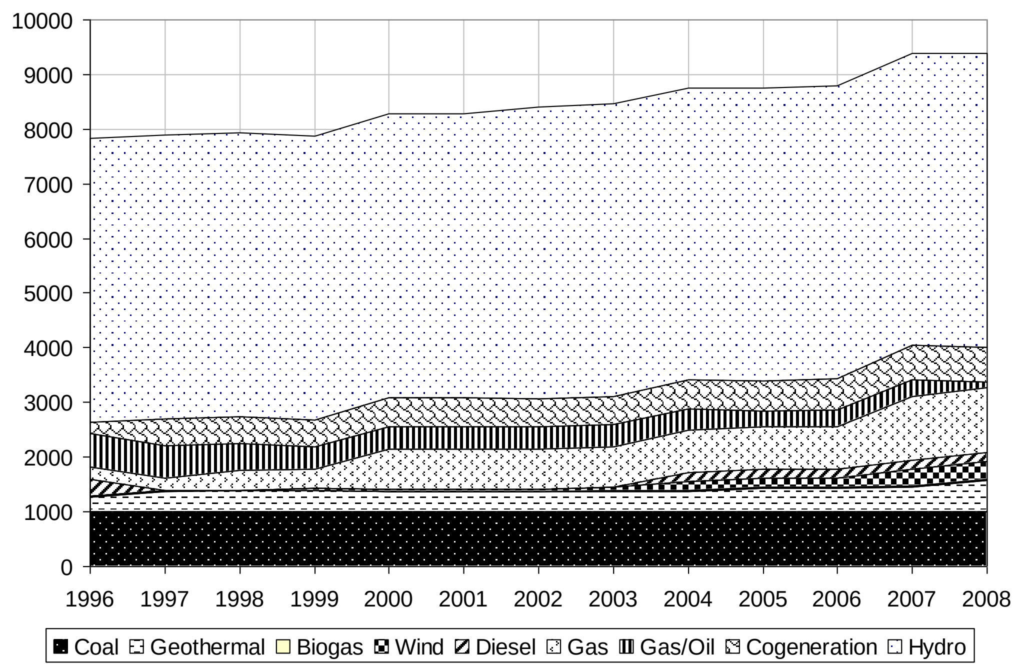


Figure 6.19: Installed capacity by resource type

Figure 6.19 shows the actual installed capacity from 1996 to 2008 by the different plant types (plotted based on MED records (Ministry of Economic

Development New Zealand 2008). Based on this information, the actual monthly potential available energy is calculated as:

Actual monthly potential energy generation = ∑ Actual <plant type> potential energy generation*8760/12

Equation 14

The actual potential energy generation for each plant type is calculated using:
Actual <plant type> potential energy generation = Actual <plant type> capacity*Average <plant type> availability factor

Equation 15

The values for the plant availability factors are as previously shown in Table 6.9. Figure 6.18 and 6.19 show the domination of hydro as a generation resource. However, hydro supply varies throughout the year and given that the hydro storage in New Zealand is not large, thermal plants are used more than usual during dry seasons to meet demand, as shown in Figure 6.20.

Price history (Figure 6.21) shows that the wholesale market price is sensitive to the hydro availability. Comparing Figure 6.20 and Figure 6.21, price spikes occurred in 2003, 2006 and 2008 during low hydro availability. The lack of hydro resources are complemented by higher generation outputs from thermal plants. The higher costs of operating thermal plants push up the wholesale electricity prices.

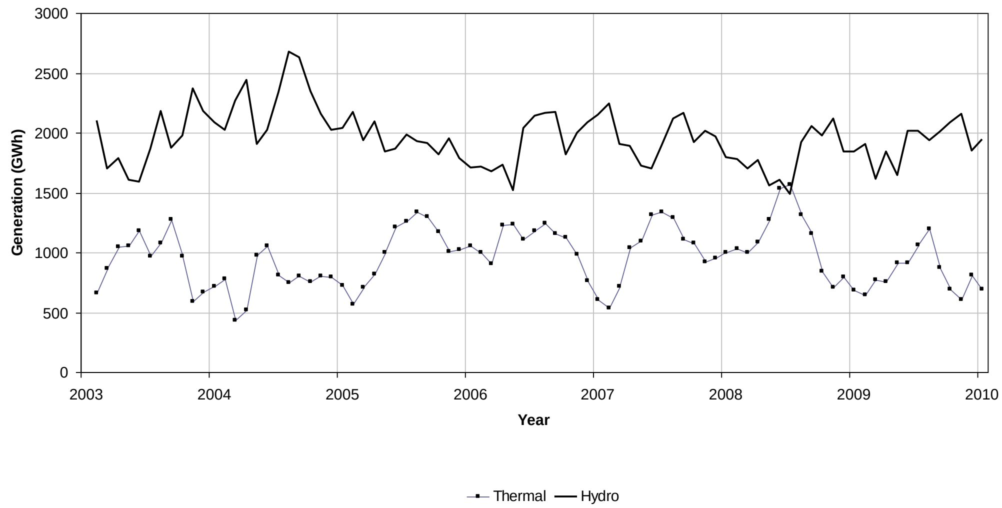


Figure 6.20: Thermal and hydro generation from 2003 to 2010

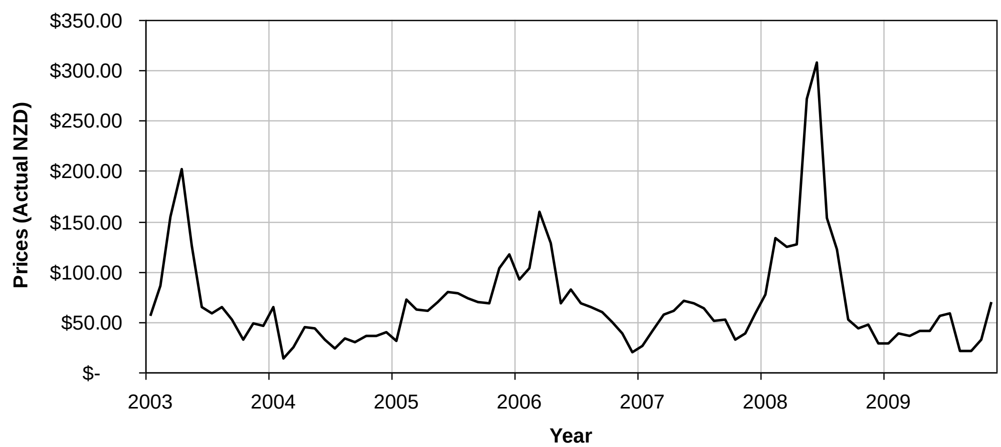


Figure 6.21: The average monthly wholesale electricity prices for the years 2003-2009 (Electricity Commission 2010)

The big impact of hydro availability on prices makes it important for the SD model to consider it as an input. Hence, hydro availability data is fed into the model using past hydro inflow data. The past hydro inflow data (Electricity Commission 2010) is plotted in Figure 6.22. The data is tabulated in Appendix B5.

Low inflows were observed in about March 2000, mid 2001 and April 2003, 2005 and 2007. High inflows were observed in October 1996 and 1998, November 1999 and December 2002. Generally, the natural lake cycles in

New Zealand are high lake levels heading into summer, reducing levels during summer (November- January) and autumn, and increasing levels during winter (May-July) and spring (Opus International Consultants Limited 2009).

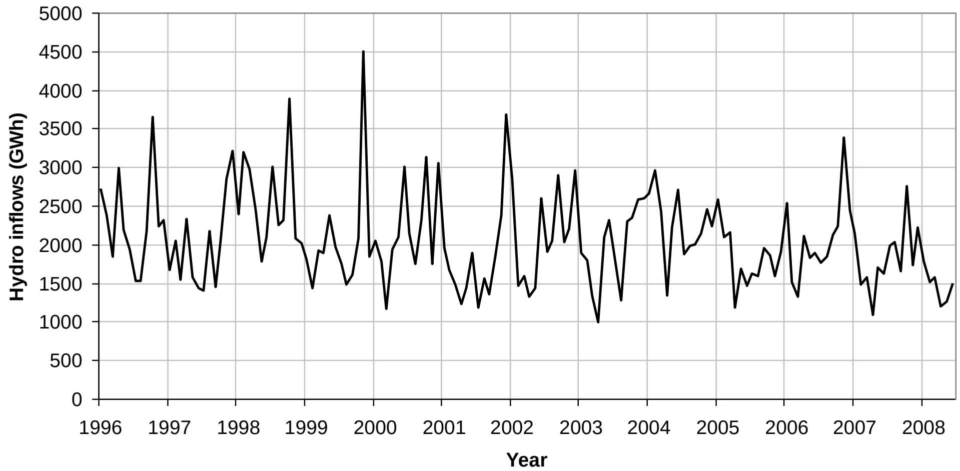


Figure 6.22: Hydro inflows in GWh from 1996 till mid 2008

The summarised monthly flow dataset is provided in GWh by Opus International Consultants Limited for the Electricity Commission. The conversion factors are based on the current hydro system and may not be correct for past (or future) time periods where the system was configured differently. The current system includes data from the following seventeen hydro systems - Waikato, Waikaremoana, Tongariro Power Development (TPD), Matahina, Mangahao, Kaimai, Aniwhenua, Wheao/Flaxy, Patea, Waitaki, Clutha, Manapouri, Cobb, Coleridge, Waipori, Highbank and Branch. Based on the data, the corresponding hydro availability factor is calculated using:

Hydro availability factor = Hydro inflows/Maximum monthly hydro energy

Equation 16

where the

Maximum monthly hydro energy = Installed hydro capacity*365*24/12

Equation 17

The calculated hydro availability factor is plotted in Figure 6.23. It is included in the model in the hydro development loop where the available hydro energy is calculated as:

Available hydro electric energy = Installed capacity hydro *hydro availability factor

Equation 18

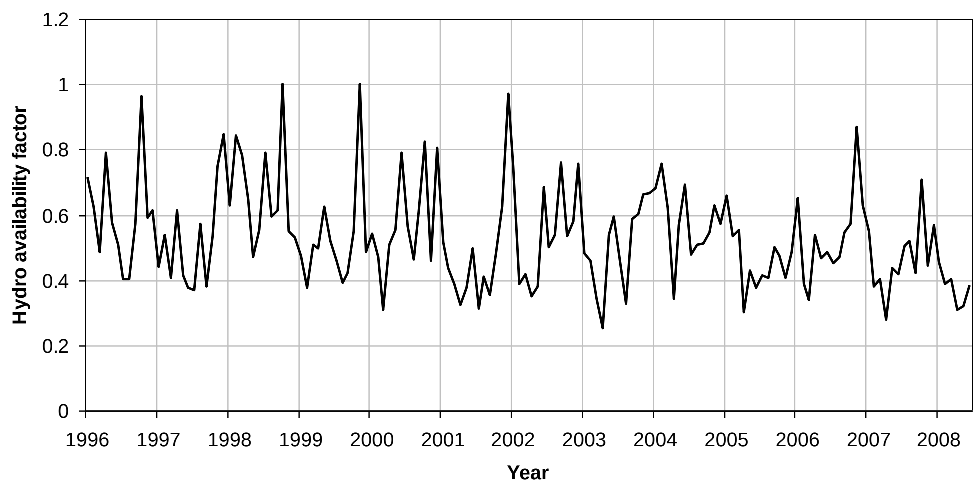


Figure 6.23: Calculated hydro availability factor

The total hydro energy is then taken into account by the variable *potential monthly generation*, which sums all the potential monthly energy generation from each plant type. As shown in the price determination loop in Figure 6.16, the generation data is then used to formulate the price.

The simulation is run from the year 2000 to June 2008. The simulation starts in 2000 because before 2000, there are only two market players – Contact Energy and ECNZ (Ministry of Economic Development New Zealand 2009). ECNZ was split into Meridian Energy, Mighty River Power and Genesis only in April 1999. The simulation stops at June 2008 because the hydro data set was only provided up to that date.

6.3.2.6 Results

To illustrate the model results for this verification stage, Figure 6.24 shows the monthly electricity supply and demand that resulted from the inputs fed into the model. Figure 6.24 shows the energy surplus, being the difference between the energy supply and demand. The figures show energy shortages in mid 2001 and mid 2003, as historically occurred in New Zealand.

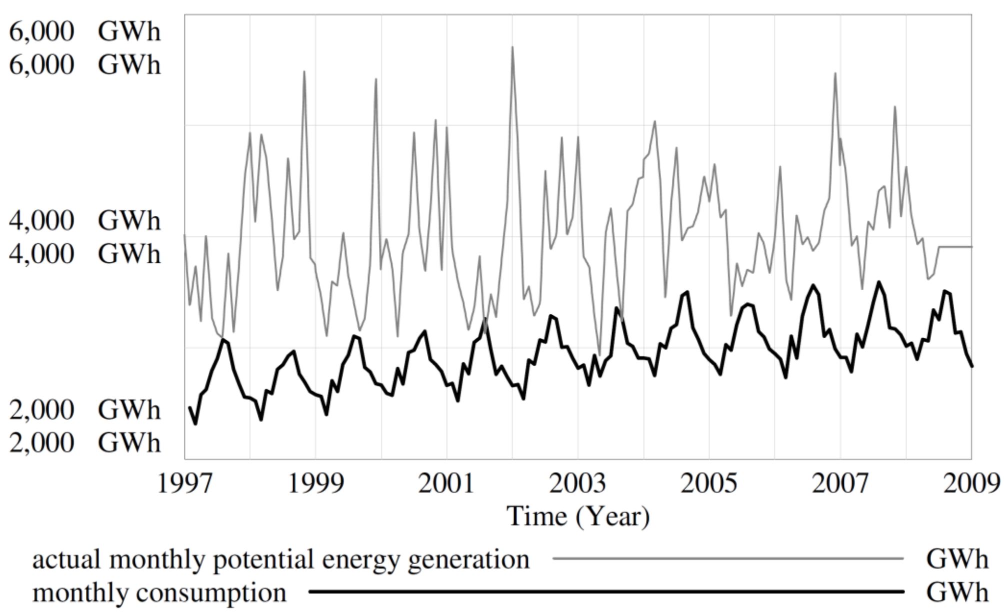


Figure 6.24: Resultant electricity supply and demand

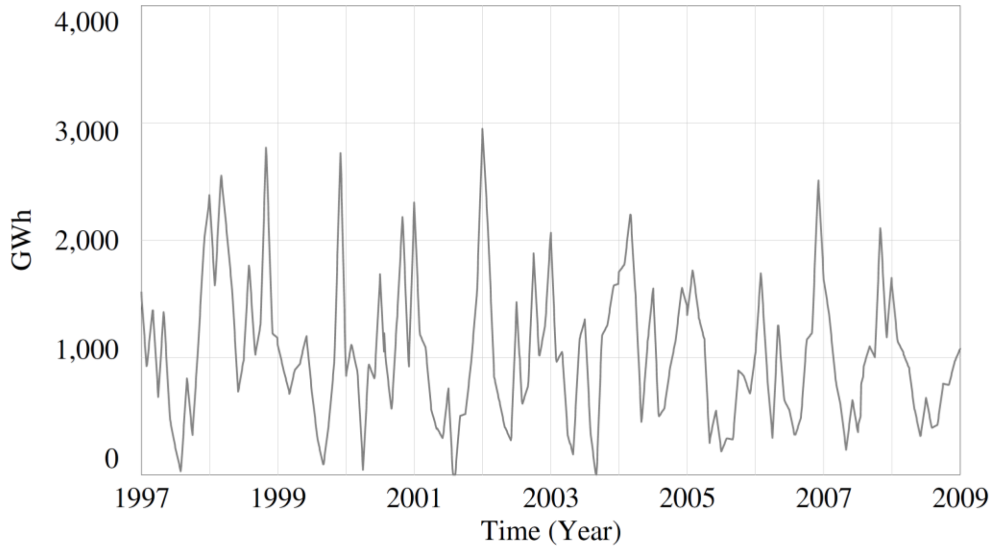


Figure 6.25: Resultant energy surplus

Based on the resultant *energy surplus*, the SD model calculates the *effective price* as described in Section 6.3.2.1. The comparison between the calculated *effective price* and past prices are shown in Figure 6.26. The price works well for the values for the year 2000 till 2003 (Figure 6.27). After 2003, the *effective price* does not accurately reproduce the past real price. However, it captures the general trend where high prices were reproduced in 2003 and 2006 as historically happened.

The differences between the *effective price* and past prices could be due to some changes to the New Zealand market after 2003 that might have affected the price behaviours. These include the introduction of the Electricity Governance Rules and the Electricity Commission in 2003 and the commissioning of a government owned peaking plant, Whirinaki in 2004. The use of Whirinaki power plant during dry years has been said to have distorted the market price (Office of the Minister of Energy and Resources 2009).

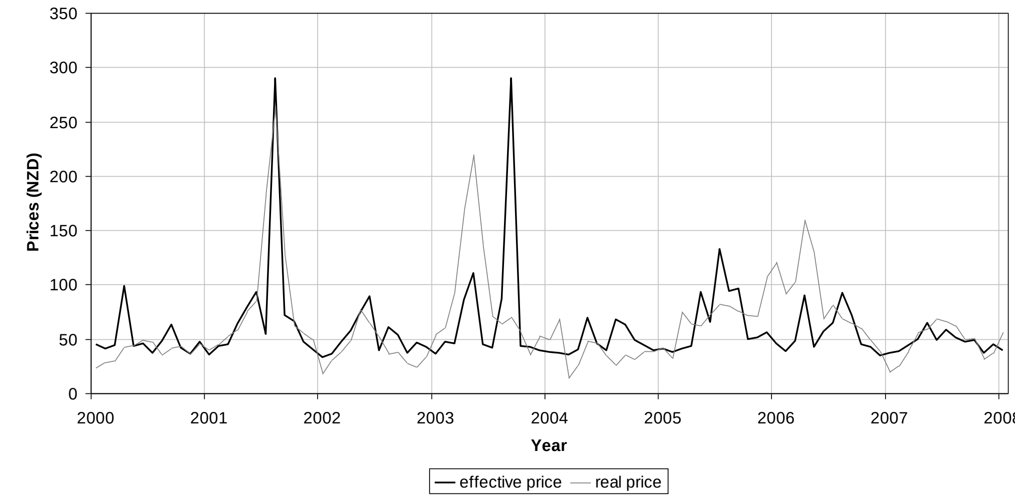


Figure 6.26: Comparison between model output (*effective price*) and historical price (real price) data

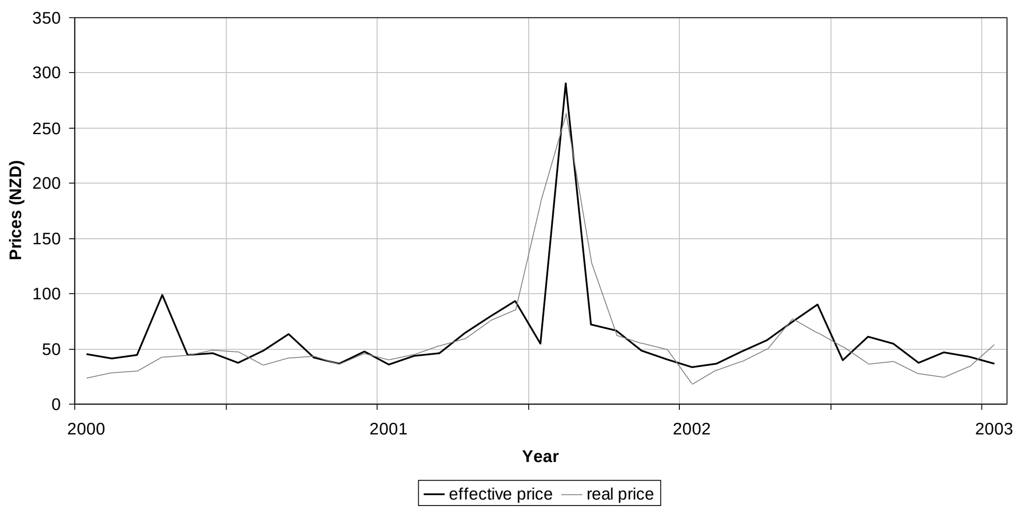


Figure 6.27: Comparison between model output and historical price data from 2000 to 2003

The resultant price trends show that price increases during small energy surpluses and reduces when the surplus is great, as suggested by basic supply and demand theory. This shows that the model price equations are able to capture this feature well and can be used; it is not the model's objective to perform accurate price forecasting. A further validation stage is undertaken and discussed in the next section to see the effectiveness of the price equation in triggering new generation investments.

6.3.2.7 Model validation – overall model verification

This final stage of the model validation uses the derived price equation to drive the whole model. The resultant installed capacity is then compared to the actual installed capacity for comparison as shown in Figure 6.28-6.35. The figures show that the SD model results did not differ much from actual historical data.

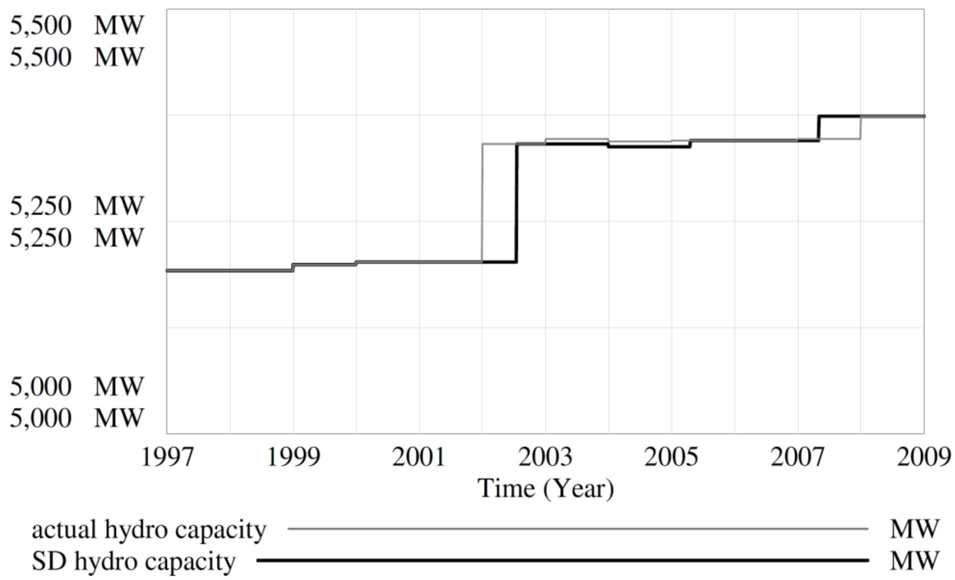


Figure 6.28: Comparison of hydro capacity

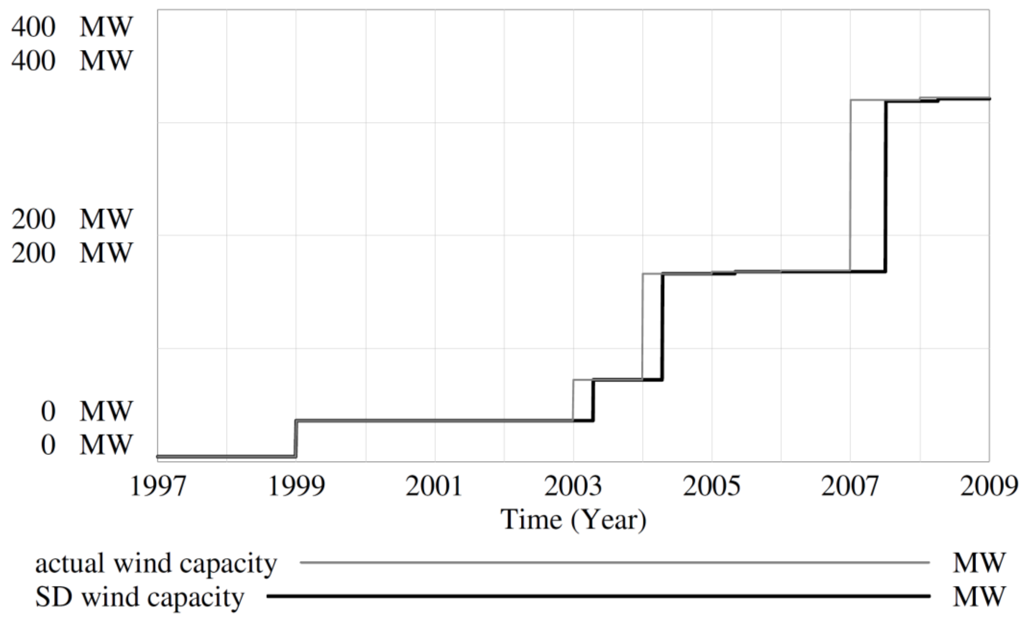


Figure 6.29: Comparison of wind capacity

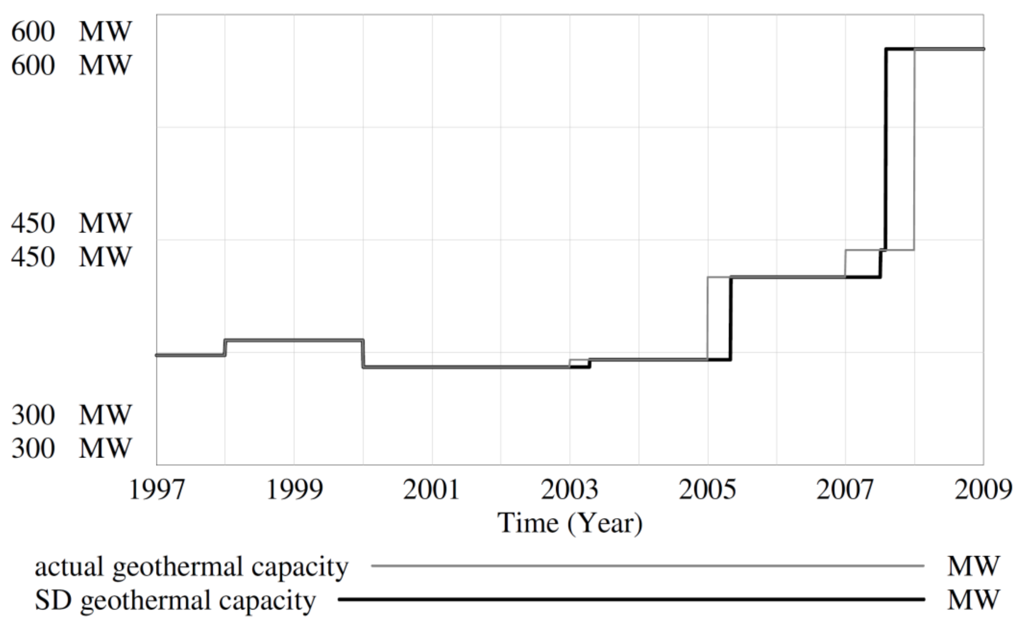


Figure 6.30: Comparison of geothermal capacity

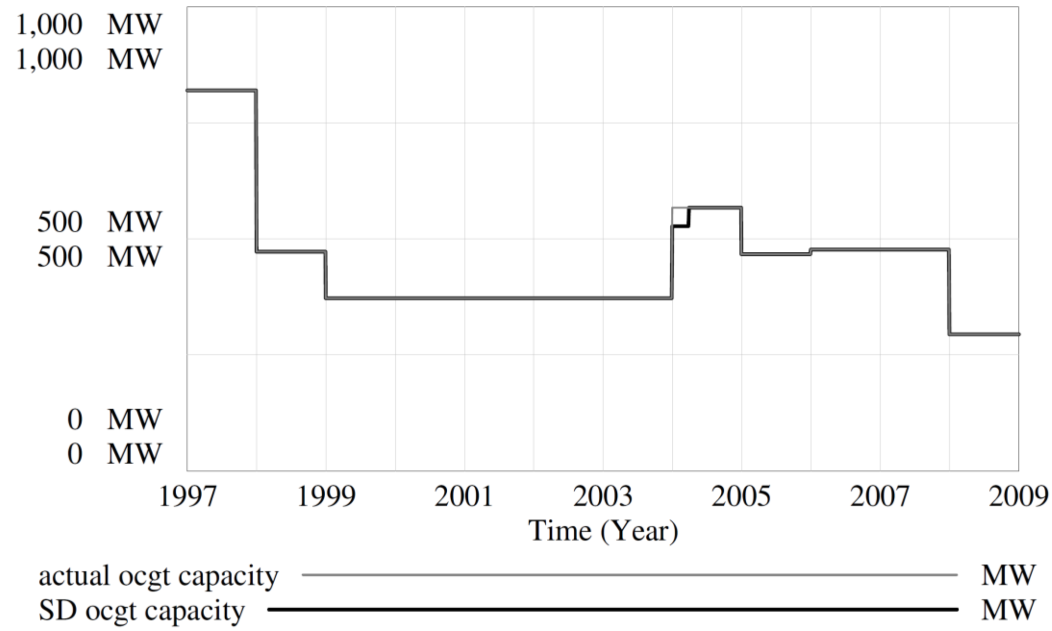


Figure 6.31: Comparison of OCGT capacity

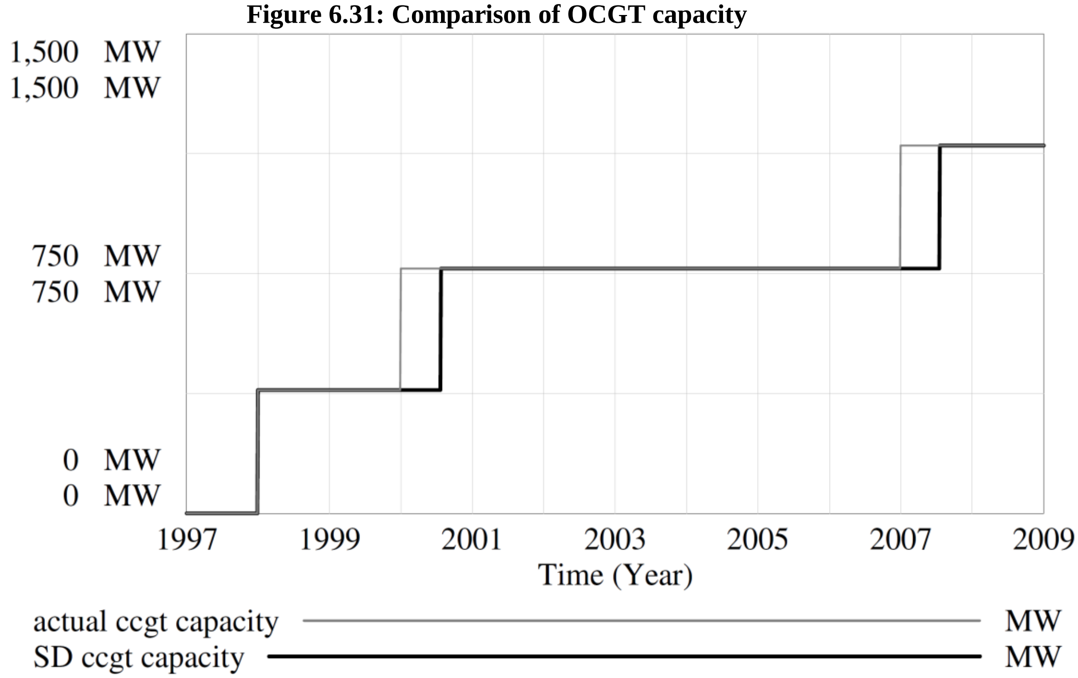


Figure 6.32: Comparison of CCGT capacity

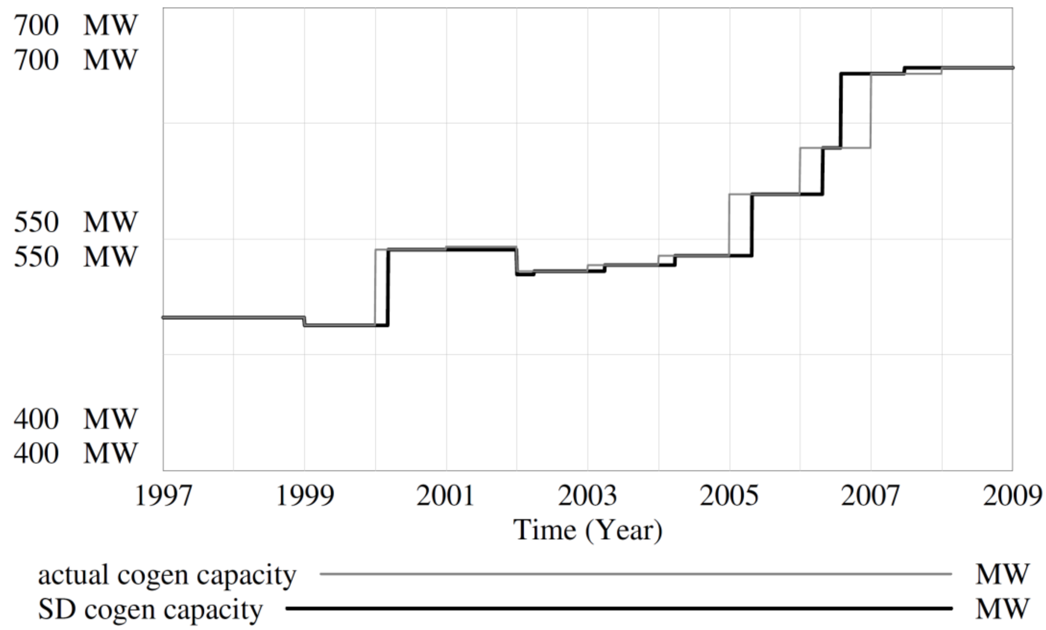


Figure 6.33: Comparison of cogeneration capacity

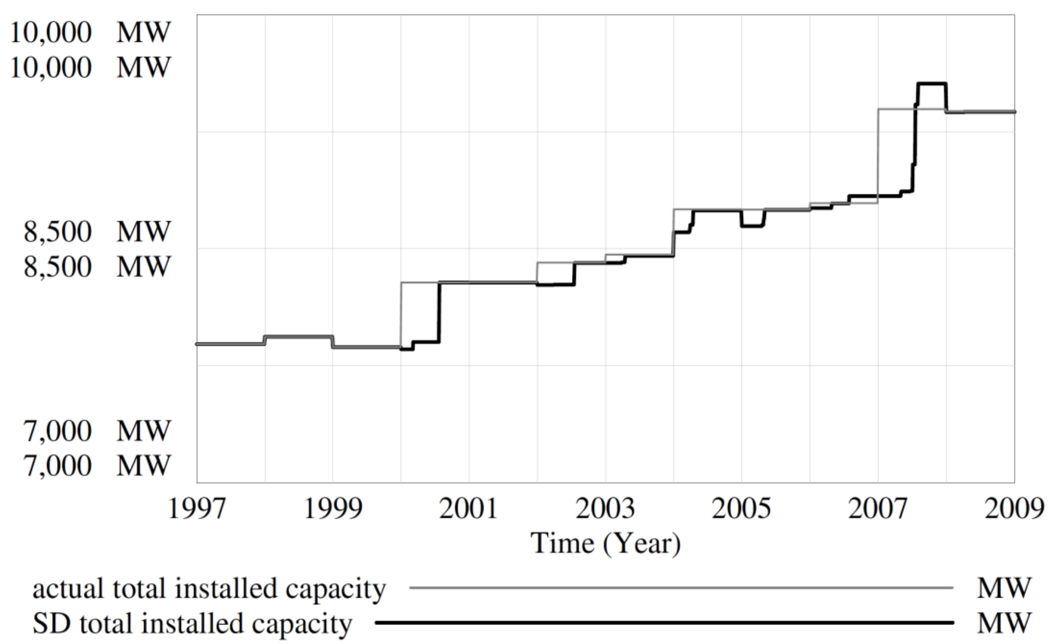


Figure 6.34: Comparison of total installed capacity

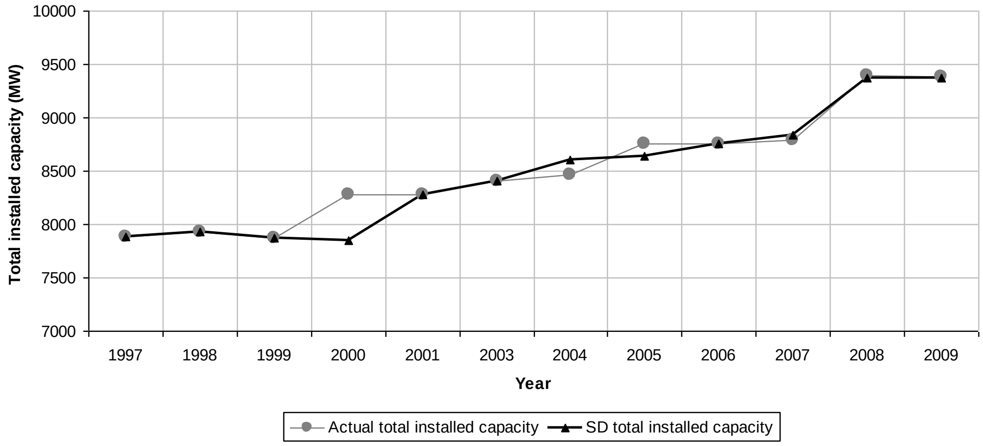


Figure 6.35: Comparison of actual data with the SD model results taken annually

6.4 Chapter summary

This chapter described how the SD model for NZEM was constructed and validated. The validation results showed that the SD model was capable of replicating historical trends in installed generation capacities. Hence, it is assumed that the developed SD model can produce realistic results when it is used to forecast future generation capacities. The use of the SD model to forecast generation trends for five different future market development scenarios are described in the next chapter.

7 SIMULATION INPUTS AND ASSUMPTIONS

This chapter discusses the inputs and assumptions that were used by the SD model. Since the SD model results were to be compared with the GEM results featured in the SOO2008, the SD model used the same inputs and assumptions as the GEM. The SD model simulations were performed to evaluate whether the generation capacity expansion schedules suggested in the SOO2008 will be able to meet the forecasted demand when the interaction between generation capacity and the electricity market is taken into account.

The chapter first describes how the generation build schedules are formulated by the GEM model for the SOO2008. The schedules are prepared for five different possible future scenarios for New Zealand. The chapter then elaborates on the assumptions and inputs that are made common to both models.

7.1 SD model updates for SOO2008 evaluation

To evaluate the SOO2008, the SD model discussed in Chapter 6 was updated to consider future scenarios, relevant for the duration of the simulated time, which is 2010 to 2050. The updates are:

- New possible technology such as IGCC and wave power is added to the modelled types of power plants
- Plant development durations are updated to include the new possible technologies
- Demand side participation is included
- Future gas and carbon prices are taken into account
- LRMC values are updated to be relevant for 2010-2050

Generally, the inputs for the SD model follow the inputs for the GEM model as per the SOO2008 to ensure that fair comparisons can be made between the results.

7.2 SOO2008 descriptions

This research uses the Statement of Opportunity 2008 (SOO2008) as its main reference in the model development. The SOO2008 are based on the simulation results of the EC's in-house model known as the Generation Expansion Model (GEM). It is a capacity expansion model for the New Zealand electricity sector. GEM is a mathematical programming (i.e. optimisation) problem of the mixed integer program (MIP) type. It is coded using the General Algebraic Modeling System (GAMS) software and is solved with the CPLEX[1] solver (Electricity Commission 2009).

Taking into account various factors, the GEM model provides the generation build schedule under different possible future scenarios as one of its main outputs. The GEM model takes the following factors into account: demand forecasts, national policies, fuel prices, hydrological and wind data, carbon prices and transmission costs. The SD model also takes these factors into account and in addition, incorporates the interaction between generation capacity and the wholesale electricity market.

7.3 Models inputs

To make fair comparisons between the GEM and the SD model results, the same GEM inputs are fed into the SD models. The SOO2008 components that are taken as inputs by the SD model are:

[1] Named CPLEX because it implements the simplex method in C programming language in solving optimization problems

(i) Records of existing power plants and committed projects

(ii) Future generation scenarios

(iii) Scheduled power plants under each scenario

(iv) Demand forecasts

(v) Future energy prices

The records on the existing power plants determine the initial conditions for both the GEM model and the SD model. The full record is provided in Appendix B1 and B2. The data is only correct at the time the EC ran its GEM model for the SOO2008. Since then, several plants have been commissioned and decommissioned. However, to make sure that the SD model results are comparable to the SOO2008, the SD model uses the SOO2008 data directly without updating it. The record as listed in the SOO2008 is summarised in Table 7.1.

Table 7.1: Summary of existing power plants by type

Plant type	Capacity (MW)
Hydro	5111
Wind	183
Geothermal	385
OCGT	205
CCGT	1320
Coal	1000
Cogeneration	284
Total	**8488**

For existing embedded generation plants that are over 10MW, the total capacity is 342MW. There are no existing wave, pumped storage or Integrated Gasification Combined Cycle (IGCC) power plants in New Zealand, but these new plant types are proposed under some of the future scenarios. The SD model categorised the power plants according to their technology type. For the evaluation of the SOO2008, the technology types are hydro, geothermal, wind, OCGT, CCGT, conventional coal, IGCC, wave and pumped storage.

7.3.1 Future generation scenarios

The SOO2008 considers five different generation scenarios:

i. Sustainable Path
ii. South Island Surplus
iii. Medium Renewables
iv. Demand-side Participation
v. High Gas Discovery

The scenario development process for the 2008 generation scenarios included three main steps (Electricity Commission 2008):

• assembling input data;

• developing the scenario 'stories' identifying the key drivers and assumptions (for example fuel cost and availability, discount rates, carbon price) which guide the future development paths in the scenarios and determine what combination of drivers will apply in each scenario; and

• running the models to develop each generation scenario.

This process is illustrated in Figure 7.1. Based on the developed scenarios and demand forecasts, the GEM produces the least cost power plant build schedules corresponding to each scenario. The build schedules are discussed in the next section.

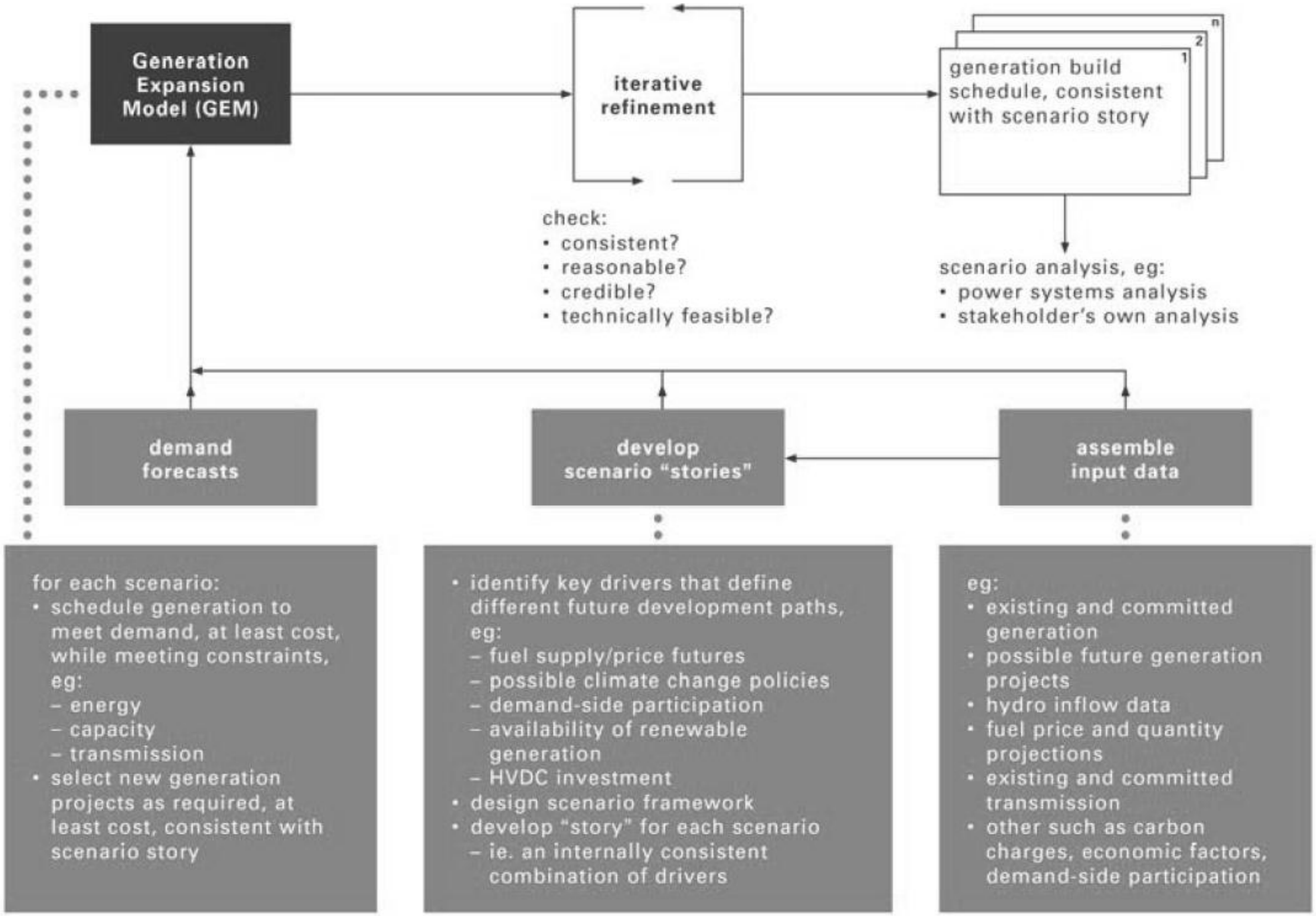


Figure 7.1: Scenario development process (Electricity Commission 2008)

The five scenarios are presented in Table 7.2. They were intended to provide reasonably credible future possibilities, while encompassing most of the uncertainties (Electricity Commission 2008).

With the national targets set out in the NZES2007 for renewable energy, the scenarios are formulated so that the following objectives are achieved (Electricity Commission 2008):

- Sustainable Path is 89 percent renewable by 2025.
- South Island Surplus is about 82 percent renewable by 2025, with a bias towards South Island wind and hydro.
- Medium Renewables is about 77 percent renewable by 2025, with more generation located in the North Island.
- Demand-side Participation is about 69 percent renewable by 2025, with extensive demand-side involvement and high electric vehicle uptake.
- High Gas Discovery is approximately 69 percent renewable by 2025, with low gas prices due to indigenous gas finds.

Table 7.2: Scenarios outline of SOO2008 (Electricity Commission 2008)

Scenario	Description
Sustainable Path (MDS1)	New Zealand embarks on a path of sustainable electricity development and sector emissions reduction. Major existing thermal power stations close down and are replaced by renewable generation, including hydro, wind and geothermal backed by thermal peakers for security of supply. Electric vehicle uptake is relatively rapid after 2020. New energy sources are brought on stream in the late 2020s and 2030s, including biomass, marine, and carbon capture and storage (CCS). Demand-side response helps to manage peak demand.
South Island Surplus (MDS2)	Renewable development proceeds at a slightly more moderate pace, with all existing gas-fired power stations remaining in operation until after 2030, though taking a more mid-order role as gas prices increase. The coal-fired units at Huntly Power Station are shifted into a reserve role and eventually removed from service. Wind and hydro generation increase considerably, particularly in the lower South Island. Relatively little geothermal energy is utilised. Thermal peakers supplement renewable development.
Medium Renewables (MDS3)	A 'middle-of-the-road' scenario. Renewables are developed in both islands, with North Island geothermal development playing an important role. The coal-fired units at Huntly transition through dry-year reserve to total closure. Thermal peakers and a new combined cycle gas turbine (CCGT) supplement renewable development. Tiwai smelter is assumed to be decommissioned in the mid-2020s.
Demand-side Participation (MDS4)	Demand-side participation becomes a more important feature of the market, driven by a desire from consumers of all types to become more fully involved. Electric vehicle uptake is high, and vehicle-to-grid technology is used to manage peaks and provide ancillary services. On the generation side, new coal and lignite-fired plants are constructed after 2020, and geothermal resources are developed. Little new hydro can be consented, however, and some existing hydro schemes have to reduce their output (due to difficulty in securing water rights). Huntly Power Station remains in full operation until 2030. Electricity-sector emissions rise, though transport-sector emissions would be lower than in other scenarios.
High Gas Discovery (MDS5)	Major new indigenous gas discoveries keep gas prices low to 2030 and beyond. Some existing thermal power stations are replaced by new, more efficient gas-fired plants. New CCGTs and gas-fired peakers are built to meet the country's power needs; the most cost-effective renewable plants are also developed. The demand-side remains relatively uninvolved.

7.3.2 *Scheduled power plants under each scenario*

To produce the build schedules for the SOO2008, the GEM incorporated the following key features (Electricity Commission 2008):

- The costs the model seeks to minimise capital expenditure on new generation plant and transmission investments, fixed and variable operating costs for all generation plant, and HVDC charges (where variable costs include operating and maintenance costs, carbon charges, fuel costs, and, where applicable, carbon sequestration costs).
- Inter-island transfers over the HVDC linked are modeled explicitly, as are transmission losses on the HVDC link.
- Upgrades to the HVDC link are assumed to occur in 2012 and 2018.
- Perfect competition in the wholesale electricity market is assumed

The proposed build schedules are as listed in Appendix C3. The build schedules are fed into the SD model as inputs for the corresponding simulated scenarios. As previously described in Chapter 6, the plant capacities are fed using step functions. The functions are set up using the following rules:

- ➢ Plants already in the development stage in 2010 get commissioned as scheduled.
- ➢ Planned power plants go through the investment decision process (as illustrated in Figure 6.3)
- ➢ Plants that are scheduled to be decommissioned, get decommissioned as scheduled

7.3.3 *Demand forecasts*

The demand forecasts utilised by both the GEM and SD models are developed by the EC's in house specialist modelling team. Forecasts are made of the following demands:

(i) Energy demand – total electrical energy demand over a period of time (in GWh)

(ii) Energy demand from potential electric vehicles usage (in GWh)

(iii) Peak demand – highest rate at which energy is consumed (in GW)

(iv) Demand side participation

7.3.3.1 Energy demand forecast

The EC used econometric models for its long term national electric energy demand forecasting. The models use an historical relationship between the electricity demand and key economic variables - gross domestic product (GDP), population, electricity prices and number of household - to produce future demand projections based on forecasts of those key drivers (Electricity Commission 2008). The key drivers forecast are included in Appendix C4.

Before the forecasts are made, the demand is split into three main sectors – residential, commercial and industrial, and heavy industrial (Tiwai aluminium smelter) – because each sector has different characteristics and hence different economic variables attached to it. Accordingly, different econometric models and assumptions are used for each, tailored to the particular characteristics, as shown in Table 7.3.

Table 7.3: Drivers used in the residential, commercial and industrial and heavy industrial model (Electricity Commission 2008)

Sector	Population	GDP	Number of households	Electricity prices	Model structure
Residential	Yes	Yes	Yes	Yes	Log based model using data from 1974 onwards.
Commercial and industrial	No	Yes	No	No	Linear model using data from 1986 onwards.
Heavy industrial (Tiwai Point aluminum smelter)	No	No	No	No	Fixed forecast based on maximum annual historical demand.

A key problem with forecasting demand over long time periods is the high level of uncertainty that arises due to potential changes in the underlying drivers. The Commission has used a Monte Carlo simulation technique to model uncertainty in the key drivers. This technique involves estimating distributions for key drivers used in the model. The model is then re-run many times, replacing the actual input data with data randomly drawn from the estimated distributions. This provides a range of forecasts that confidence limits can be based on (Electricity Commission 2008). The resulting national energy forecast with 80 percent confidence limits is shown in Figure 7.2. The corresponding data table is provided in Appendix C5.

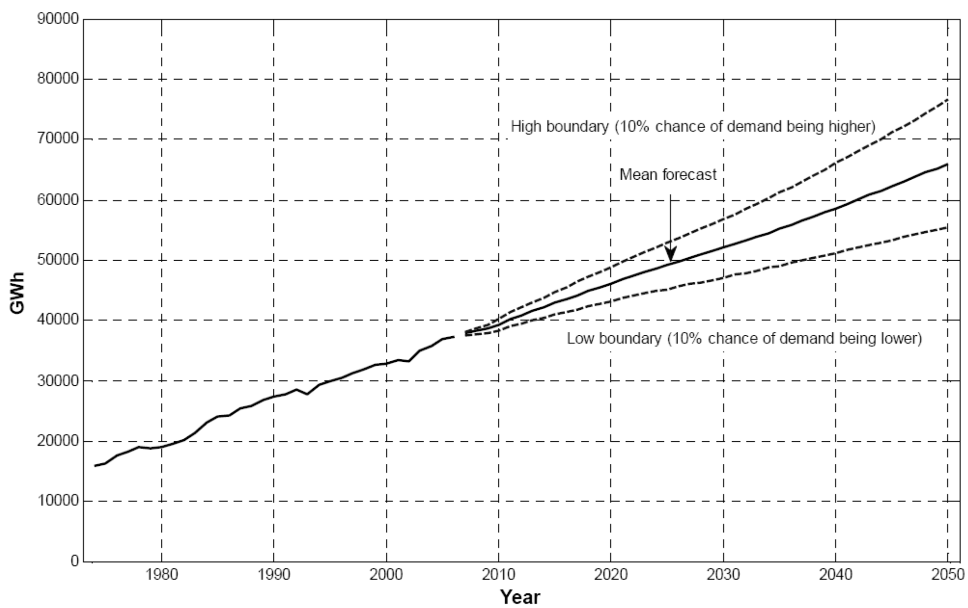


Figure 7.2: National electric energy forecast with 80% confidence limits (Electricity Commission 2008)

Based on the given aggregated demand forecasts in the SOO2008, the total annual forecasted demand for each scenario is summarised as shown in Figure 7.3. MDS1 and MDS4 have higher demands to include demands from electric vehicles, whereas MDS3 has a lower demand due to the decommissioning of the Tiwai aluminium smelter in the mid 2020s.

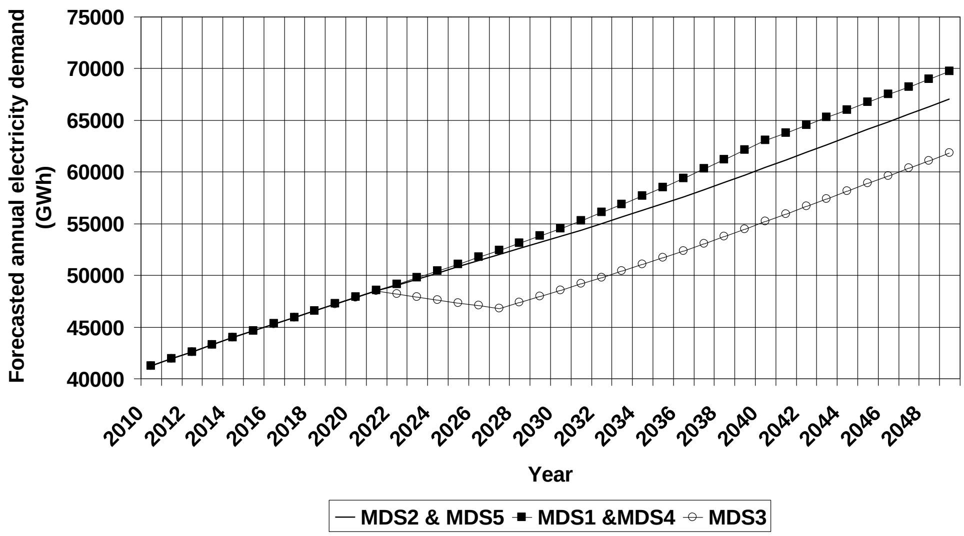


Figure 7.3: Electrical energy demand baseline forecasts for all scenarios (Electricity Commission 2008)

The GEM model performs its analyses at a regional level and hence the input data for the SOO2008 are aggregated regionally. Hence, to evaluate whether the projected generation capacity in SOO2008 is sufficient to provide the national energy demand, the regional energy demands are summed up before being fed into the SD model. Similar to the GEM model, the SD model also looks at the demand on a monthly basis so that seasonal demand variations can be captured.

7.3.3.2 Plug in hybrid electric vehicles (PHEV) or electric vehicles (EV) forecasts

The electric vehicle demand has been modeled as an additional component of demand, added to the base forecast in two of the five scenarios, namely the Sustainable Path and Demand-side Participation scenarios. The electric vehicle demand forecast is based substantially on an electric vehicle penetration scenario developed by the Ministry of

Transport (MoT), using their vehicle fleet emissions model. The projected demand increase is shown in Figure 7.4.

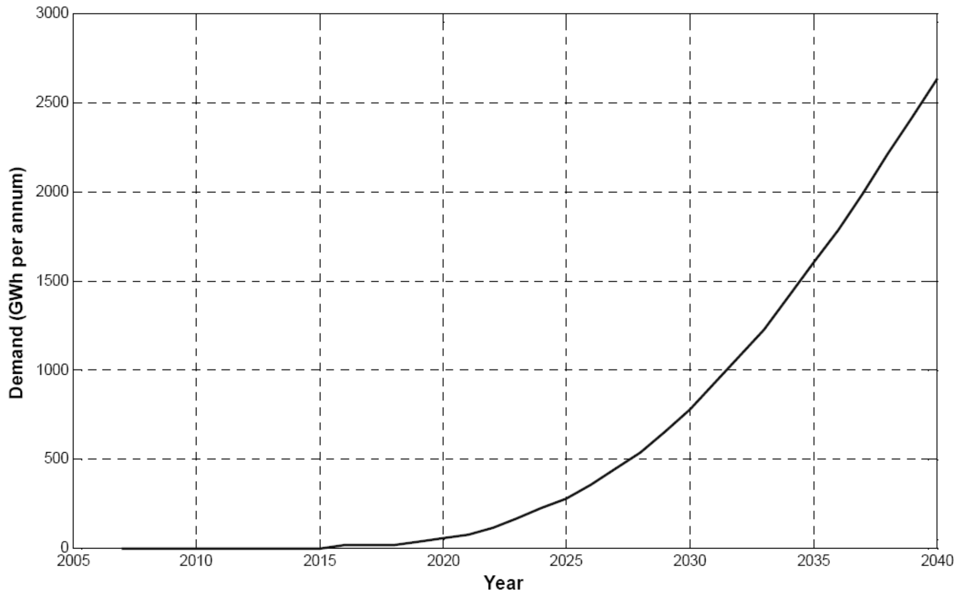


Figure 7.4: Demand increase projection for electric vehicles (Electricity Commission 2008)

7.3.3.3 Peak demand forecast

Peak demand forecasts are important for investment decision making and determining the type of required power plants. The peak demand in this context is defined as the maximum of the average demand levels in all the half-hours ('trading periods') in a calendar year (as opposed to the highest instantaneous demand). Typically, demand peaks occur on weekdays in winter; they can occur either in the morning (often around 8am) or in the early evening. They are generally associated with cold weather events during which domestic heating demand is high (Electricity Commission 2008).

The peak forecasts are annual (representing the highest projected half-hourly demand occurring in a given calendar year), and cover the period from 2012 to 2049. The expected forecasts are calculated as projections of the historical peak demand series. In the longer term, peak demand growth is projected to proceed at the same rate as energy demand growth. EC assumed that the usage of EVs does not affect the peak demand growth.

Demand growth in some regions is adjusted for known changes at specific sites. For example, it is assumed that the electricity demand of the aluminum smelter at Tiwai will plateau at 605 MW, rather than continuing to grow as it has in recent years. This resulted in a different growth projection under MDS3 where it is assumed that the aluminum smelter would be decommissioned in the mid 2020s. The resulted forecasts are shown in Figure 7.5 for the baseline as well as low and high growth projections under all scenarios except MDS3. Figure 7.6 shows the forecasts under MDS3. The forecasted peak demand values are tabulated in Appendix C6.

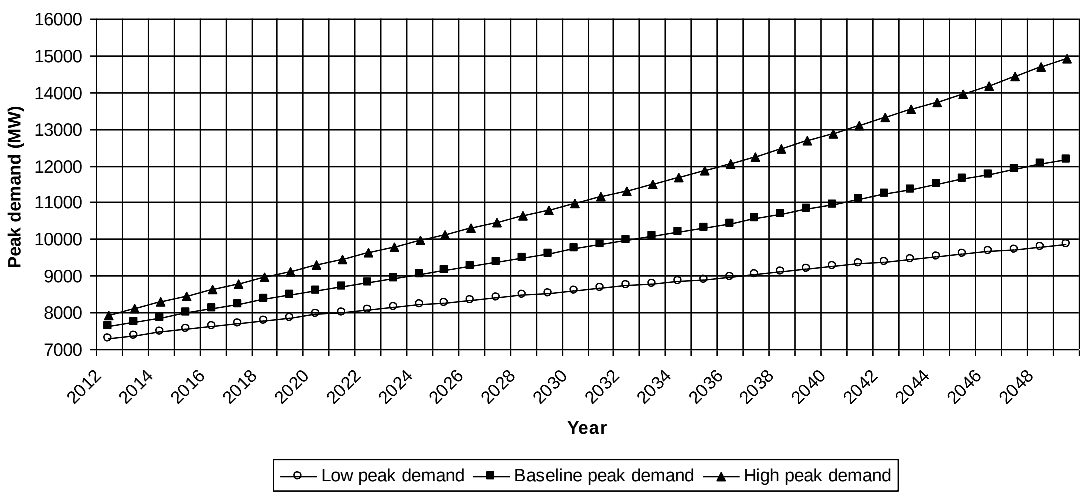


Figure 7.5: Peak demand forecasts for New Zealand from 2012 to 2048 under all scenarios except MDS3 (Electricity Commission 2008)

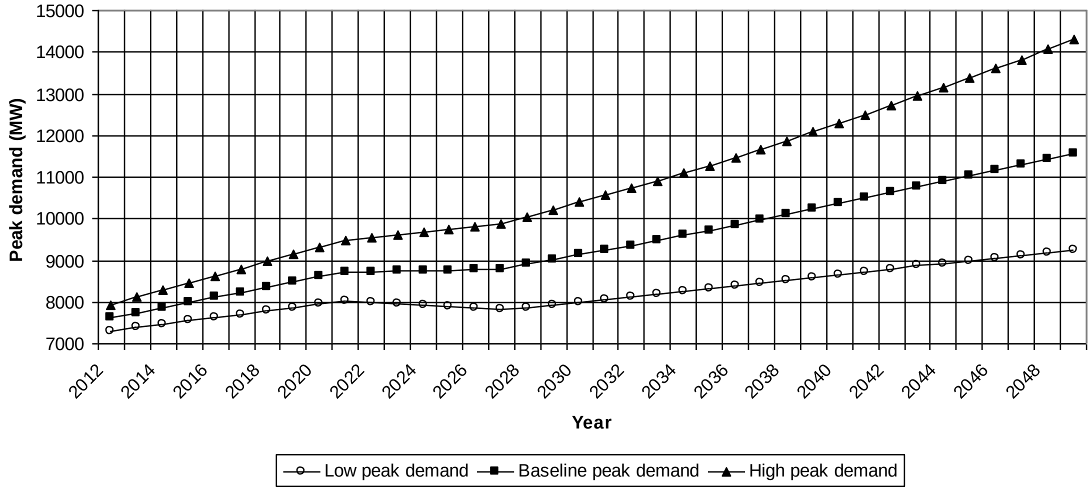


Figure 7.6: Peak demand forecasts for New Zealand from 2012 to 2048 under MDS3 (Electricity Commission 2008)

7.3.3.4 Demand side participation

Demand side participation can avoid the need to build a new power plant and hence should be incorporated in generation expansion planning. Unlike many other countries, demand side participation is already significant in New Zealand. Currently, there are consumers offering their hot water heaters as interruptible loads (IL). ILs are electrical loads that can be quickly disconnected by a central agency. Participation in IL provision is voluntary and is compensated for. The distribution companies then offer these loads in a similar way a generator offers a capacity to Transpower in managing peak load demands. Under MDS4, vehicle to grid technology is also considered as a potential IL.

Demand side management refers to voluntary load reductions in response to price, and can be supported by a range of initiatives including demand side bidding, time-of-use pricing, and/or demand-side aggregation. This is expected to become significant in the future with the rollouts of smart meters to customers.

Both the GEM and SD model treat the demand side participation as a potential generating unit and as part of the list of scheduled power plants (Appendix C3).

7.3.4 Future generation costs

A key aspect of the generation input data is the relative economics of the various types of generation. Table 7.4 to 7.6 describe the costs of the modeled generation technologies, in terms of long-run marginal cost (LRMC) and short-run marginal cost (SRMC).

7.3.4.1 LRMC

LRMC is defined as the mean price (at the relevant GIP) that is sufficient to cover all plant costs (in this context this includes capital financing costs, carbon costs, fuel costs, O & M and transmission charges but excludes network loss costs). A real pre-tax discount rate of 8% has been assumed in the calculation of the LRMC. Assumed depreciation rates vary between technologies. LRMCs depend on plant factor and have been calculated for several different plant factors, where applicable. Connection costs have not been included in the LRMCs shown here (but are modeled in GEM). The LRMCs shown here may differ with those published in other documents due to differences in assumed project life, depreciation rate, treatment of tax, discount rate, plant factor and/or types of cost considered (Electricity Commission 2008). Both costs depend on carbon prices and fuel prices. The forecasted carbon and fuel prices are discussed in the following sections.

The EC assumptions about LRMCs for thermal technologies are shown in Table 7.4 . Two sets of prices are shown, to indicate the range of values. Thermal plant LRMCs also depend strongly on the assumed plant factor. A plant operating as mid-order (plant factor in the ballpark of 50 percent) faces a higher LRMC per unit output than a similar plant operating as base load. On the other hand, the mid-order plant has the flexibility to run when prices are higher, so will earn more revenue per unit output. Plants running in a peaking capacity have extremely high LRMCs (much higher than their SRMCs).GEM determined the plant factor of each plant in each simulated year on a least-cost basis, within the limits imposed by the technology.

Table 7.4: LRMC corresponding to the plant availability factors for thermal power plants (Electricity Commission 2008)

Plant types	Plant availability factor (%)	LRMC ($/MWh) – gas at $7/GJ, no carbon charge	LRMC ($/MWh) – gas at $10/GJ, carbon at $30/tonne
Combined Cycle Gas Turbine (CCGT)	90	75	107
Open Cycle Gas Turbine (OCGT)	20	215	261
Coal	90	85	111
Integrated Gasification Combined Cycle (IGCC) with Carbon Capture Storage (CCS)	90	119	123

Assumed LRMCs for renewable technologies are shown in Table 7.5. These assumptions indicate that the best available resources of wind, hydro and geothermal are each around the $80/MWh level. Geothermal generation has a relatively low LRMC, in part because geothermal has no fuel cost and a high capacity factor, and in part because of the moderate capital costs assumed for geothermal projects. LRMCs of near-future geothermal generation options typically range from $70 to $90/MWh, based on a capital cost of $3000 to $4000/kW. Wind and hydro have lower capacity factors, but can still be economic where capital costs are low enough (Electricity Commission 2008).

Table 7.5: LRMC corresponding to the plant availability factors for renewable power plants

Plant types	Plant availability factor (%)	LRMC ($/MWh)
Hydro	50	85
Geothermal	90	80
Cogenerationeration	70	130
Marine	45	125
Wind	45	80

7.3.4.2 SRMC

SRMC is defined as the marginal cost, at the relevant grid injection points (GIP), of producing the next unit of electricity (in this context, including carbon costs, fuel costs and variable operation and maintenance (O & M), but excluding capital expenditures (CAPEX), fixed routine O&M , transmission charges and network loss costs). Due to the relatively lower O&M for renewable technology power plants, the SRMC is more significant for fossil fuel power plants, especially the peaking plants, as shown in Table 7.6. The SRMC is very much affected by fuel prices, and by carbon prices once the Emission Trading Scheme becomes more significant.

Table 7.6: SRMC of existing fossil fuel power plants

Plant (example)	SRMC ($/MWh) – gas price at $7/GJ, no carbon charge	SRMC ($/MWh) – gas price at $10/GJ, carbon charge at $30/t	SRMC ($/MWh) – gas price at $13/GJ, carbon charge at $50/t
Taranaki Combined Cycle	56	90	119
Whirinaki diesel plant	280	304	320
Huntly units 1-4 on coal	52	81	100

7.3.4.3 Fossil fuel prices

The three main fossil fuels currently used for electricity generation in New Zealand are natural gas, coal and oil. New Zealand has a plentiful supply of coal which could meet its needs in the long run. However, it seems unlikely that natural gas will continue to be available in large quantities, at current prices, in the long-term. The availability and price of natural gas are important drivers of the scenarios.

The future price of natural gas is unknown and difficult to predict. Among other things, the price will depend on the price of carbon, the extent of new gas discoveries around New Zealand, and whether an LNG terminal is constructed for the importation of liquefied gas. In the absence of new gas discoveries, the amount of gas available will decline and the price will increase, eventually to very high levels. New gas discoveries will tend to increase the amount of gas available and reduce its price, unless the gas is exported. The availability of imported LNG would tie the price of gas to the international LNG price and potentially allow large volumes of gas to be imported. The gas price paths assumed in the scenarios are shown in Figure 7.7.

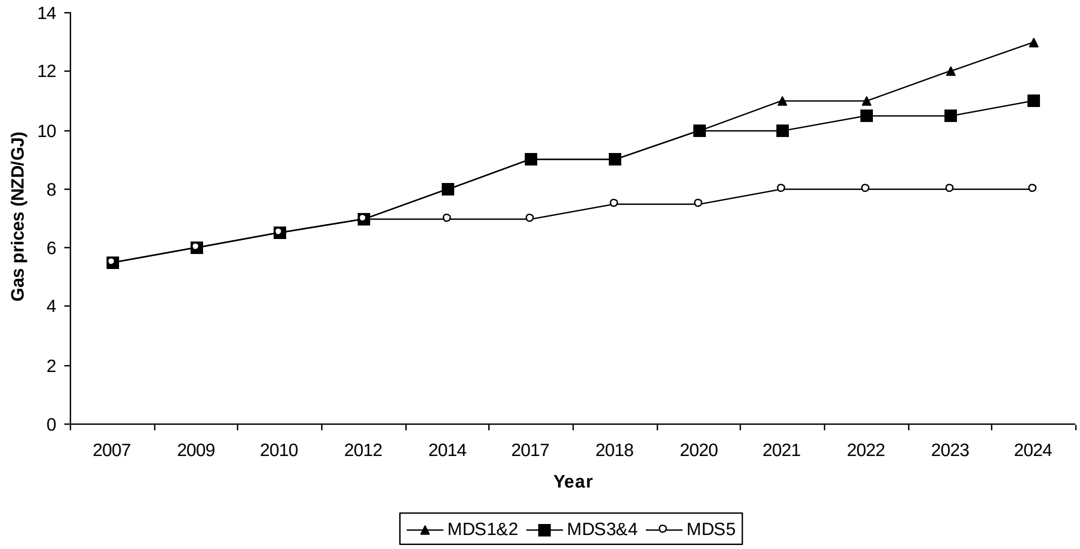


Figure 7.7: Modelled gas prices for the five scenarios (exclusive of the cost of carbon) (Electricity Commission 2008)

The gas prices shown are denominated in NZ$/GJ, paid for base load electricity generation. They do not include charges for flexible gas supply (chargeable by OCGT plants), the cost of carbon (section 7.3.4.4), or charges for gas transmission.

Each scenario follows one of three outcomes for the gas market.

- In the Sustainable Path and South Island Surplus scenarios, it is assumed that no LNG terminal is constructed (perhaps because high international carbon prices cause worldwide fuel substitution from coal to gas, increasing the international demand for gas and making it difficult for New Zealand to secure a supply). Gas prices rise to $13/GJ by 2024, and less than 60 PJ per year is used in the electricity sector. At this price, renewable plants tend to displace gas-fired generation.

- In the Medium Renewables and Demand-side Participation scenarios, it is assumed that an LNG terminal is commissioned in 2020. Based on advice from the MED and consistent with estimates in the NZES2007, it is assumed that gas prices rise to

$11/GJ by 2024 and remain steady at that level indefinitely, and that unlimited amounts of gas can be obtained at that price.

- In the High Gas Discovery scenario, it is assumed that new gas finds provide an ongoing supply of gas at relatively affordable prices. Up to 120 PJ per year is available at a price of $8/GJ.

It is assumed that the gas price is highest in scenarios where the assumed carbon price is highest. It might be argued that high carbon prices would lead to reduced use of gas and hence lower gas prices. The counter argument would be that high carbon prices would lead to reduced gas exploration and/or substitution of gas for coal, both of which would result in higher gas prices.

There is also uncertainty about the future price and availability of oil for electricity generation. However, the sensitivity to these parameters is relatively low, since the scenarios only use oil in small quantities to fuel peaking generation. All scenarios assume that up to 25 PJ per year of diesel can be used for electricity generation; this constraint is never approached. Following advice from the MED, the future price of oil for electricity generation is assumed to be $25/GJ in all scenarios except the Sustainable Path scenario, where it assumed to rise to $35/GJ by 2020 following a 'peak oil' scenario. Future prices of $4/GJ for black coal and $1.80/GJ for lignite are assumed (Electricity Commission 2008).

7.3.4.4 Carbon prices

Effective of July 2019, generation companies have to pay for the greenhouse gases that their plant emits according to the implemented Emission Trading Scheme (ETS). All five of the generation scenarios assume that there is a price on carbon required to pay for greenhouse gas emissions. The framework of carbon charging may change over time. The current proposed Emission Trading Scheme (ETS) is a broad-based, economy-wide cap-and-trade scheme that is neutral between domestic and international emissions reduction. Future measures to curb greenhouse emissions may or may not use the same framework.

In the SOO2008, EC has modeled the cost of carbon as a flat rate applied to all electricity-sector emissions, denominated in real NZ$/t CO_2-equivalent. The future price of carbon in the New Zealand electricity sector is unknown and difficult to predict. Many different estimates have been published, based on a number of methodologies. These have included modeling simulations and comparative analyses, and have typically produced estimates with large standard errors, reflecting the uncertainty associated with the factors being considered. Nevertheless, expectations seem to be that the price of carbon will rise over time, with indicated price estimates in the range of $20/t to $60/t over the next ten years and potentially significantly higher after that.

In the SOO2008, the EC has used a range of carbon prices, to indicate the uncertainty about the price path. The assumed long-run price of carbon varies from NZ$20/t (Demand-side Participation) to NZ$60/t (Sustainable Path). In all the scenarios, the EC assumes the price of carbon applies from 2010, when the electricity sector comes under the ETS. The price starts low due to free allocation of some units, but increases until it reaches its long-term level in 2018; it remains constant thereafter. The resulting price paths are shown in Figure 7.8. In practice, carbon prices might fluctuate widely from year to year.

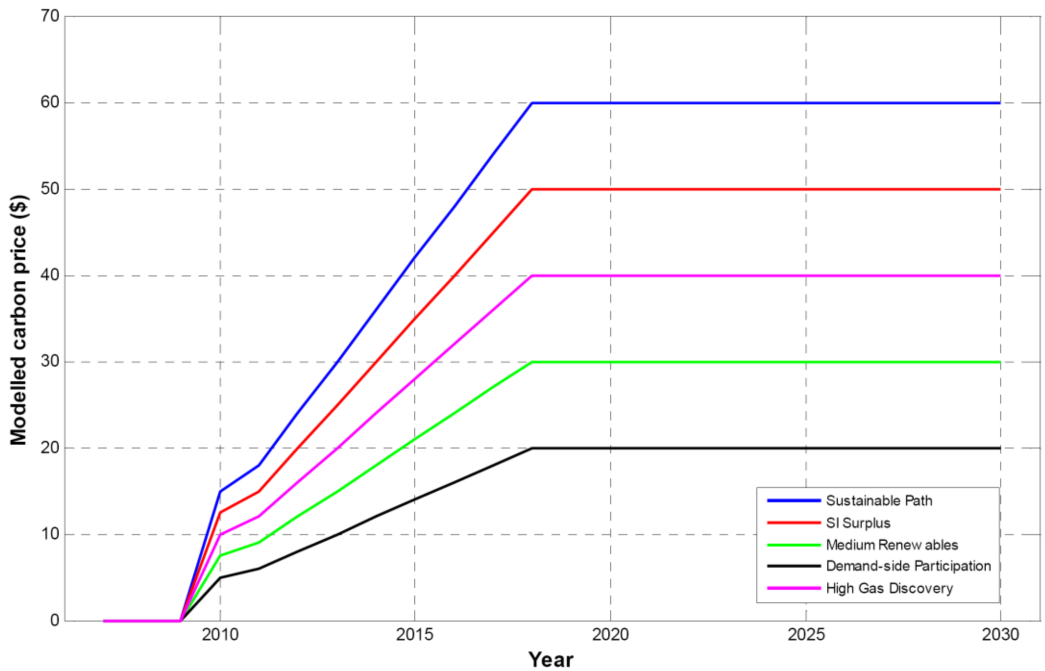


Figure 7.8: Modelled carbon prices for the five scenarios (Electricity Commission 2008)

7.4 Chapter summary

This chapter described the inputs that were used by the GEM and SD model used to forecast future generation trends in New Zealand. The main inputs were the five possible market development scenarios, consumption trends and generation costs. The consumption trends and generation costs under some of the scenarios differed from other scenarios because of the key assumptions made in developing them.

8 RESULTS COMPARISONS AND DISCUSSIONS

The SD model is run to simulate the years 2010 until 2050 to allow its results to be compared with the GEM model's results shown in the SOO2008. The results from the SD and GEM models are compared in terms of the installed generation capacities. From the SD model simulations, the resultant ECM and CM for each MDS are determined. The result comparisons and discussions are arranged according to their simulated scenarios (i.e. MDS1 to MDS5). Part of the results discussed in this chapter had been published in AUPEC2010 (Jalal and Bodger 2010) and PSCE2011 (Jalal and Bodger 2011).

The results shown here are for the simulations using the baseline future load forecasts (as illustrated in Figure 7.5 and listed in Appendix C5). The plants' availability factors were set to their maximum values as shown in with their corresponding costs listed in Table 7.4 and Table 7.5.

The simulations discussed in this chapter were also run assuming no delays in power plant developments. Even though the plant build schedules in the SOO2008 are for the years up to 2040, the SD model was run until 2050 to observe when any delayed plants get commissioned. The build schedules for each MDS are listed in Appendix C3. In the SD model, the power plants proceed to the next development phase only when market conditions are perceived to provide profits, as illustrated in Figure 6.3.

8.1 Results comparisons for MDS1 (Sustainable Path)

8.1.1 MDS1 descriptions

As described in Table 7.1, MDS1 assumes a high penetration of renewable resources in the generation mix. The scheduled plants are mainly hydro, wind and geothermal. Pumped storage and wave plants are introduced after 2020. Most existing thermal plants are decommissioned by 2025. Development of new thermal plants is discouraged by the high gas and carbon prices shown in Figure 8.1. The high gas prices result from the assumption that there will be no import of Liquefied Natural Gas (LNG). Among all scenarios, MDS1 assumes the highest eventual carbon price ($60/tonne of CO_2 equivalent) by 2018. Only clean coal and gas technology such as IGCC and CCGT plants with carbon capture and storage (CCS) technology are scheduled to be built (Electricity Commission 2008) as base power plants. However, OCGTs are scheduled for development so that they can act as peaking plants.

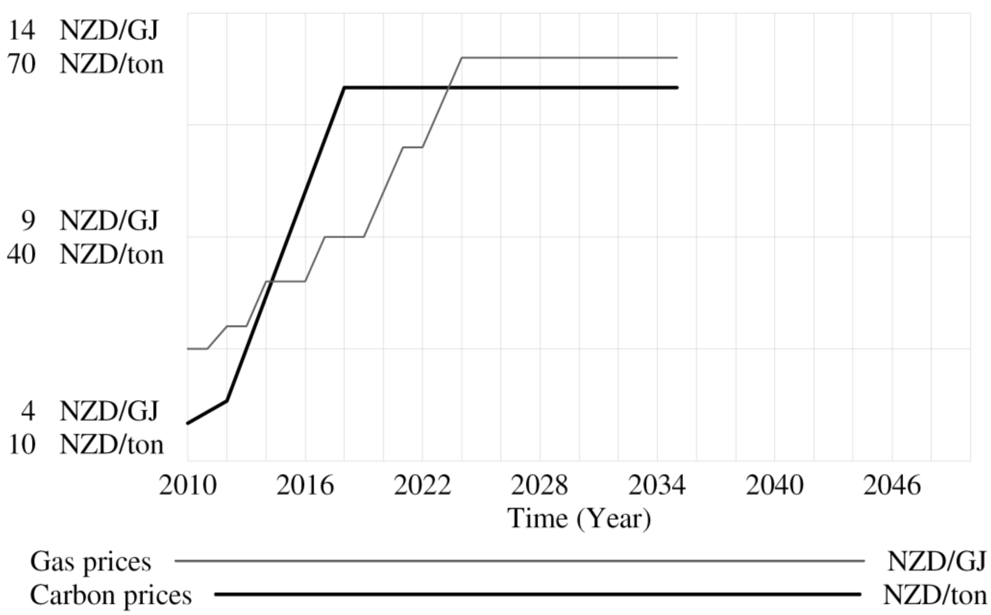


Figure 8.1: Modelled gas and carbon prices for MDS1, extracted from Figure 7.7 and 7.8

8.1.2 Installed generation capacities comparisons for MDS1

The resultant total installed generation capacities from the two models are shown in Figure 8.2. It shows that the installed capacities in the SD model lag behind the build schedules proposed in the SOO2008. This is due to investors waiting for the right wholesale market price before investing to allow for maximum profit. The simulated monthly averaged spot market price is shown in Figure 8.3. As expected, the prices are higher in the winter months. The simulated prices for MDS1 are generally low with the calculated mean of NZD74.42/MWh.

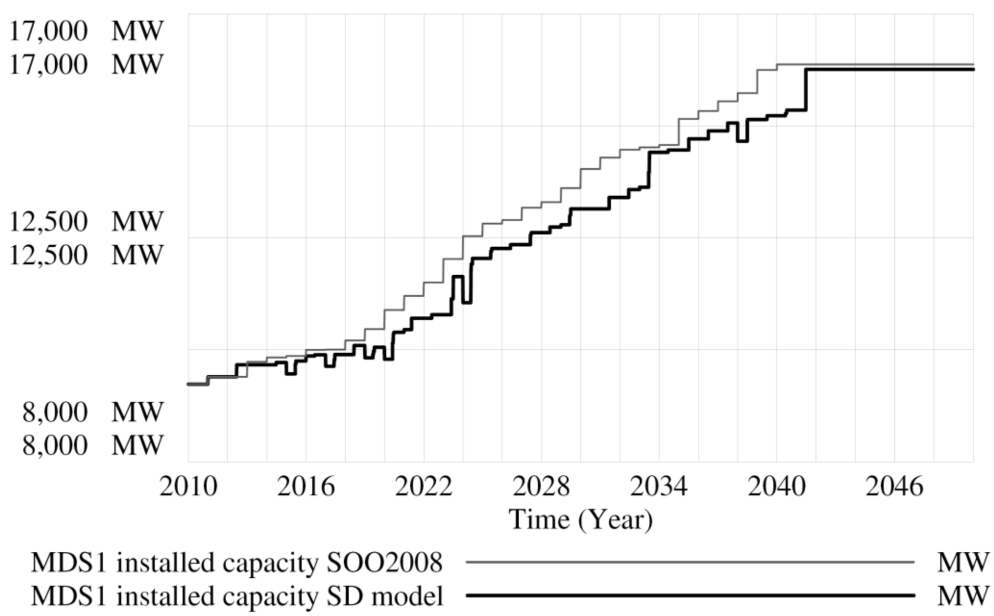


Figure 8.2: Total installed generation capacities comparisons for MDS1

For MDS1, capacity boom and bust cycles are not obvious as the observed capacity dips are only for several months. By 2050, the SD model generates less total installed generation capacity as compared to the GEM model. Looking at the results for each plant type, it is observed that all the scheduled OCGT plants will not be installed by 2050, as shown in Figure 8.4. The reason for this is due to the insufficient difference in the supply and demand margin that results in spot market prices not reaching high enough to trigger investments in the OCGT technology. Figure 8.3 shows that the forecasted prices after 2022 are lower than the OCGT's LRMC (Figure 8.4). Hence, it is predicted that all the scheduled OCGTs will not be commissioned.

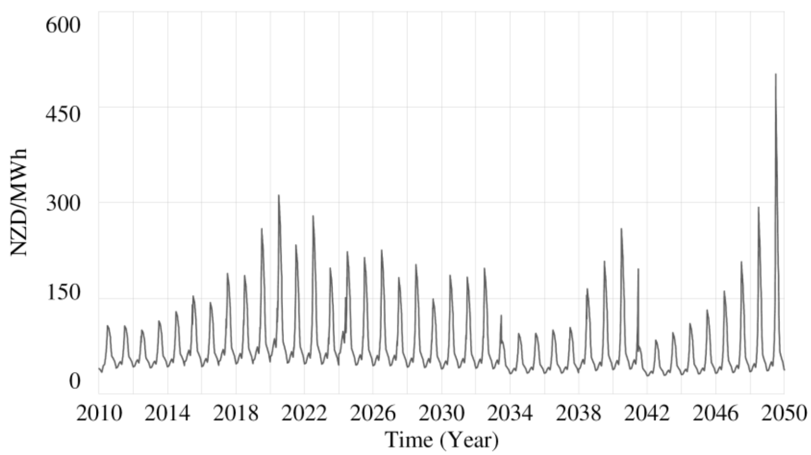


Figure 8.3: Forecasted monthly averaged wholesale electricity price for MDS1

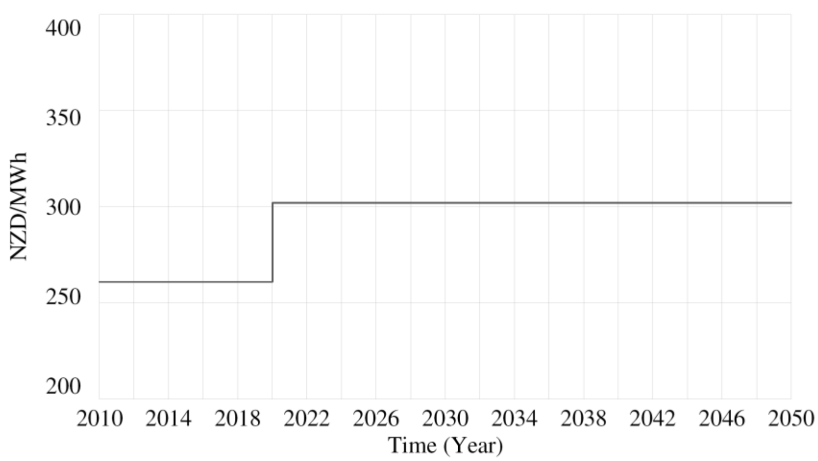


Figure 8.4: Modelled LRMC for OCGT technology under MDS1

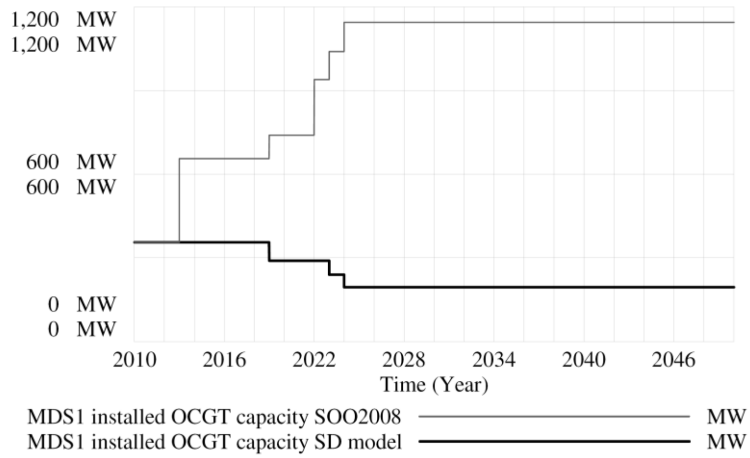


Figure 8.5: Results comparison for installed OCGT capacity for MDS1

Most plants using other technology get commissioned without much delay (see Appendix D1) except for the CCGT and pumped storage plants. Due to their higher LRMCs, the CCGT and pumped storage plants seemed to face delays of almost two years in order to wait for the market price to be conducive for their developments (see Figure 8.6 and Figure 8.7). The CCGT plants LRMC are higher under MDS1 because it is assumed that gas and carbon prices will be higher. However, all of their scheduled capacities get commissioned by 2040. This is consistent with the MDS1 scenario target where more renewable plants will be dominant by 2040. However, being more reliant on renewable resources can make the supply vulnerable under certain weather conditions. This vulnerability is investigated in Chapter 9.

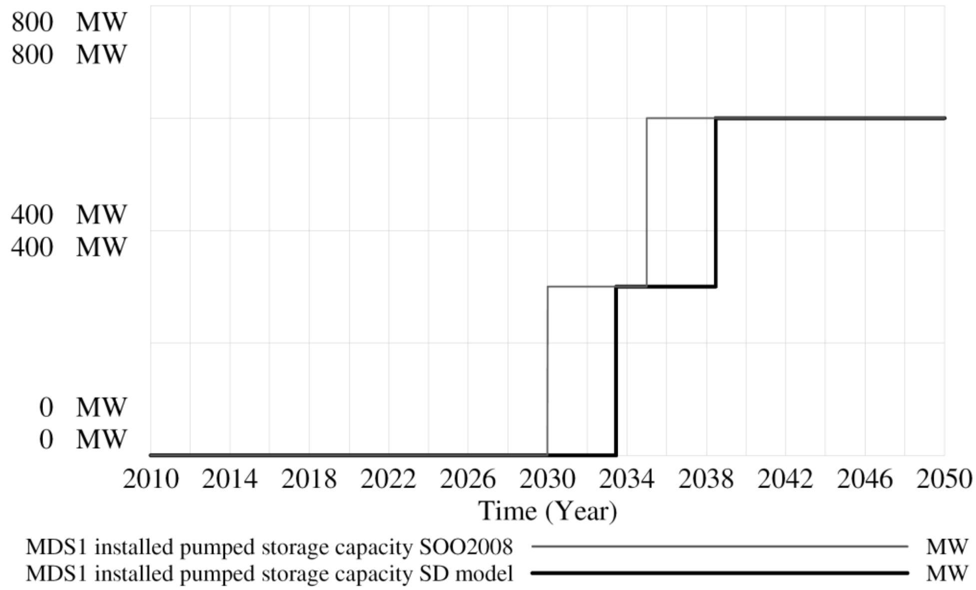


Figure 8.6: Results comparison for installed pumped storage capacity for MDS1

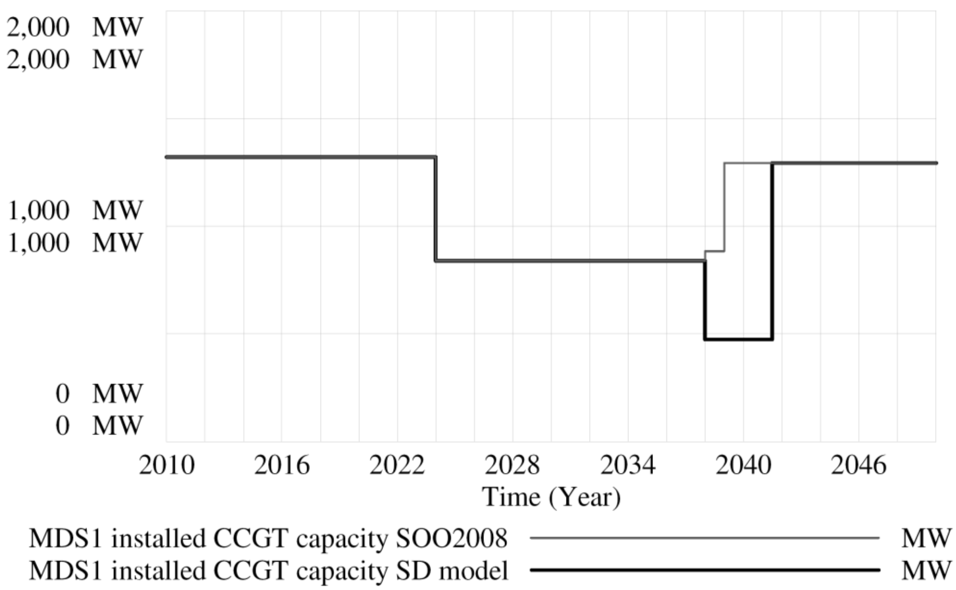


Figure 8.7: Results comparison for installed CCGT capacity for MDS1

8.1.3 Resultant ECM for MDS1

Figure 8.8 shows the corresponding ECM for the SD model results. The ECM remains positive but dips low around 2020, 2022 and around 2040. If a dry year occurs during these years, a shortage may occur. The higher ECMs from 2033 onwards indicate that the supply is adequate and no new plants are required to meet the demand. This is reflected in the forecasted wholesale electricity prices shown in Figure 8.3. As expected, the ECM after 2042 declines rapidly with no new plants being scheduled (since the build schedules are only up to the year 2040).

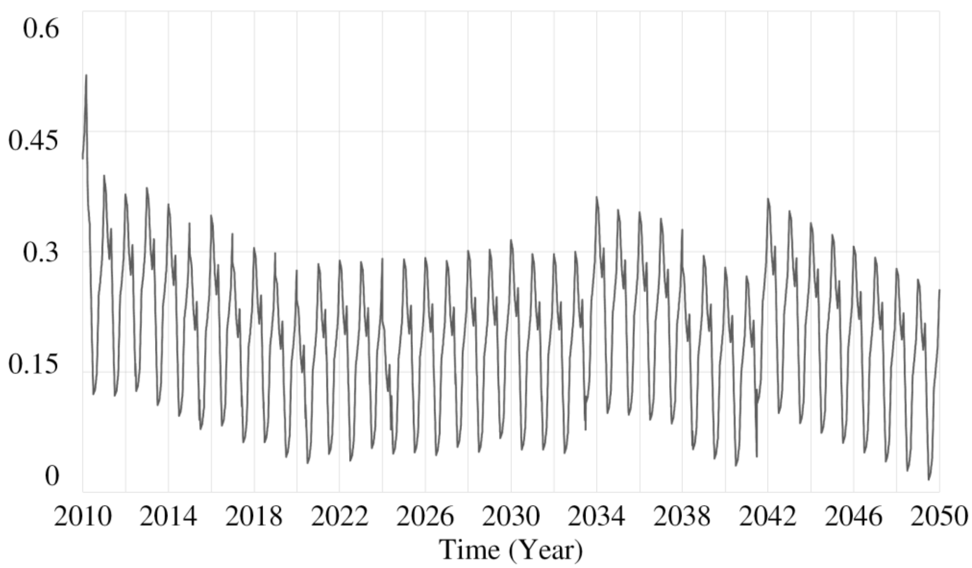


Figure 8.8: Resultant ECM for MDS1

8.1.4 Resultant CM for MDS1

In terms of peak demands, the simulated CM shown in Figure 8.9 indicates that New Zealand will not have problems in meeting its future peak electricity demands.

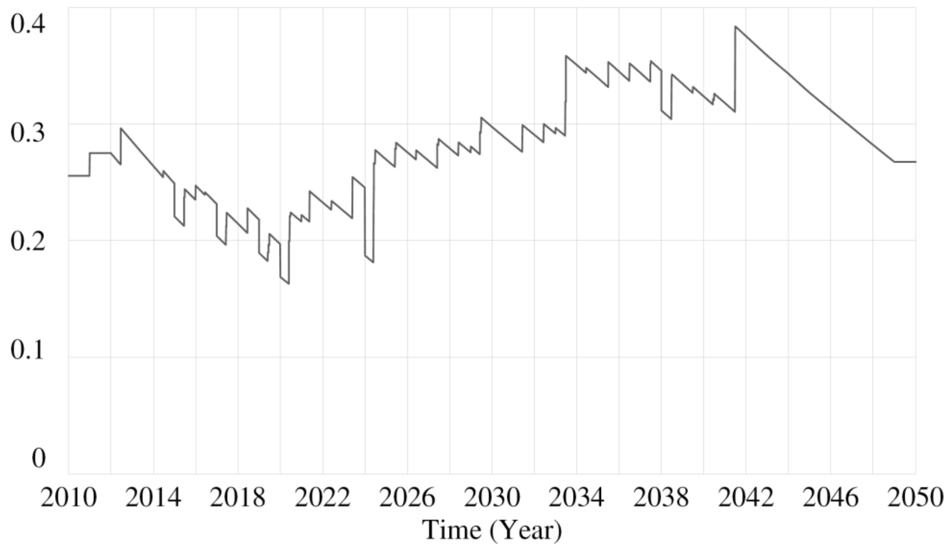


Figure 8.9: Resultant CM for MDS1

Results comparisons for MDS2 (South Island Surplus)

8.1.5 MDS2 descriptions

MDS2 is characterised as having most of the generation resources coming from the South Island with extensive hydro and wind availability. Developments of new geothermal and thermal power plants are restricted. Most thermal plants have reduced operation by 2023. The modelled gas and carbon prices are shown in Figure 8.10. The modelled gas prices are the same as MDS1 but the carbon prices rose to only NZD50/tonne of CO_2 equivalent.

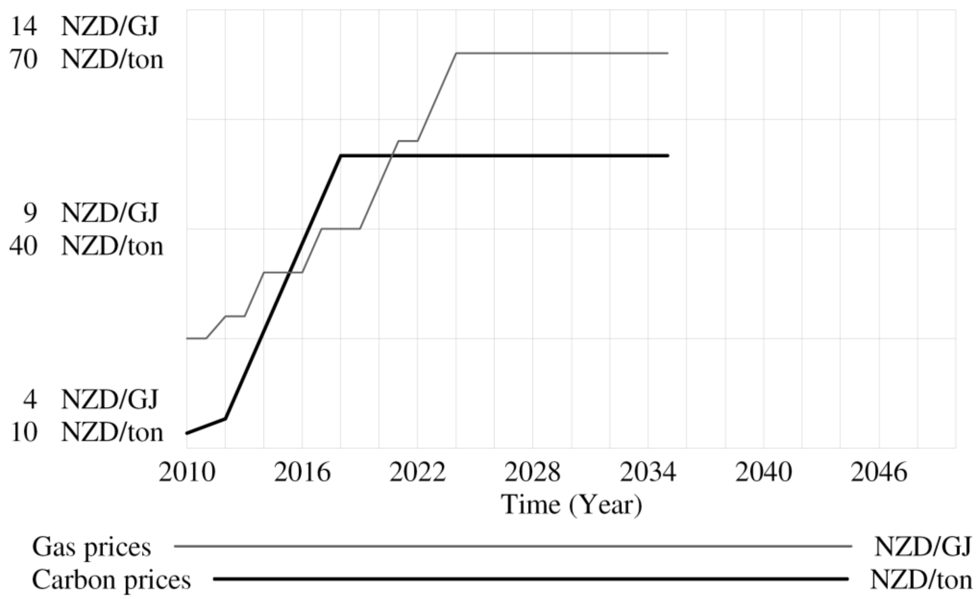


Figure 8.10: Modelled gas and carbon prices for MDS2, extracted from Figure 7.7 and 7.8

8.1.6 Installed generation capacities comparisons for MDS2

Figure 8.11 shows that for MDS2, the SD model results lag behind the SOO2008 proposed schedule. Capacity cycles are not obvious as the capacity dips are only for several months except from the year 2038 to mid 2039. By 2050, the SD model eventually generates the same total installed capacity as the GEM model.

The simulated spot market price is shown in Figure 8.12. Prices spike in the mid of 2038 and 2039 (resulting from the long capacity dip). Prices start to increase again after 2045 indicating the need for new power plants to be scheduled. Looking at the results for each plant type, it is observed that scheduled OCGT and IGCC capacities get delayed to wait for the wholesale electricity price to increase, as shown in Figure 8.13 and Figure 8.14 respectively. Figure 8.12 shows that the forecasted wholesale electricity prices are generally lower than the LRMCs for OCGT and IGCC until the price hikes in mid 2038 and mid 2039. Cogeneration plants (Figure 8.16) also face substantial delays because of their relatively higher LRMC ($130/MWh) compared to other renewable technology (about

$85/MWh). All other plants using other technology gets commissioned without much delay (see Appendix D2).

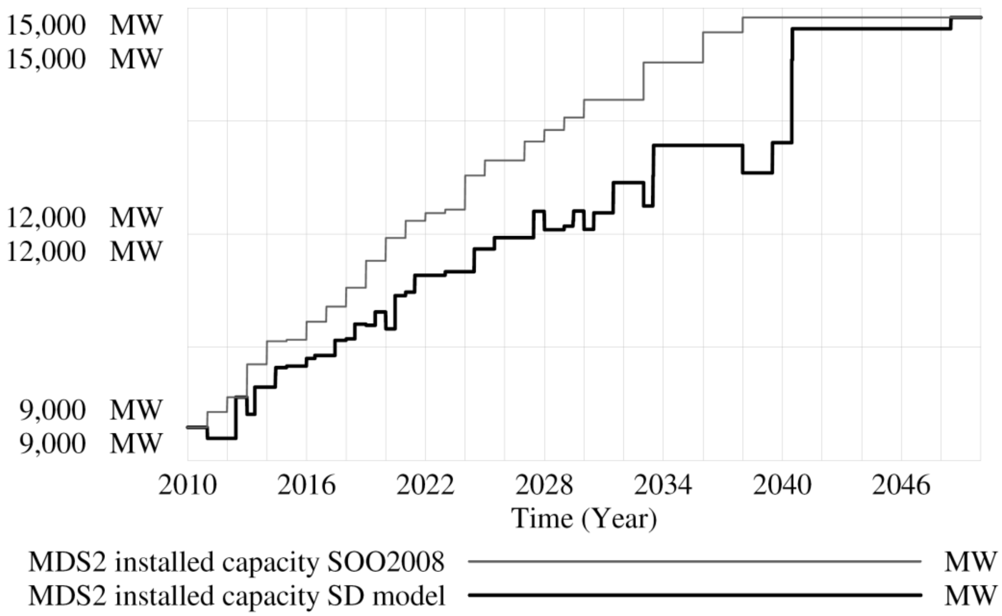


Figure 8.11: Total installed generation capacities comparisons for MDS2

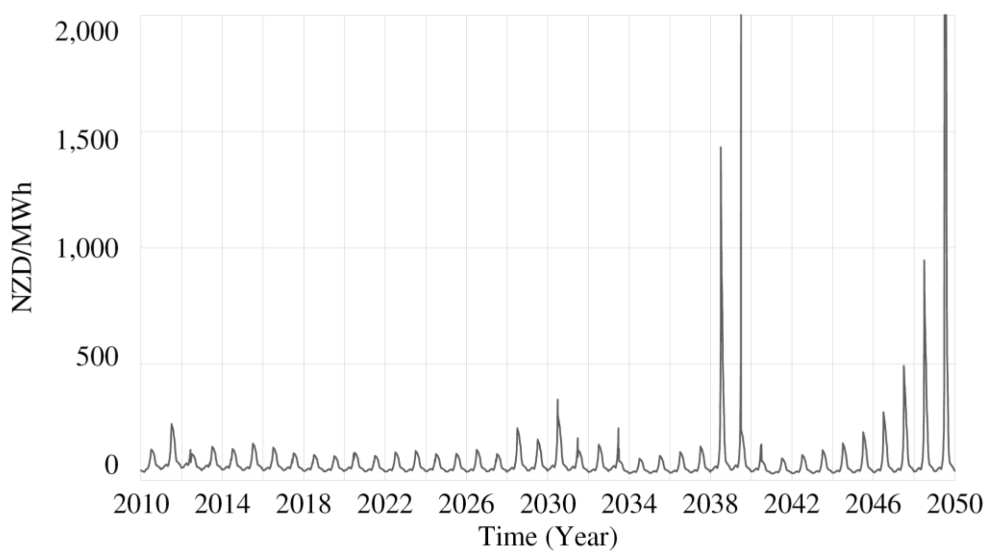


Figure 8.12: Forecasted monthly averaged wholesale electricity price for MDS2

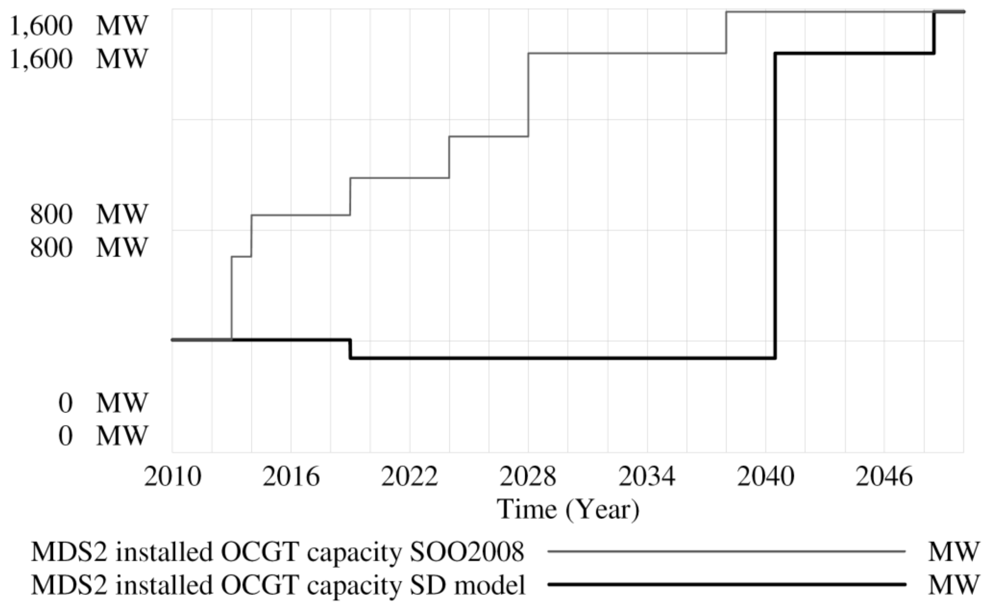


Figure 8.13: Results comparison for installed OCGT capacity for MDS2

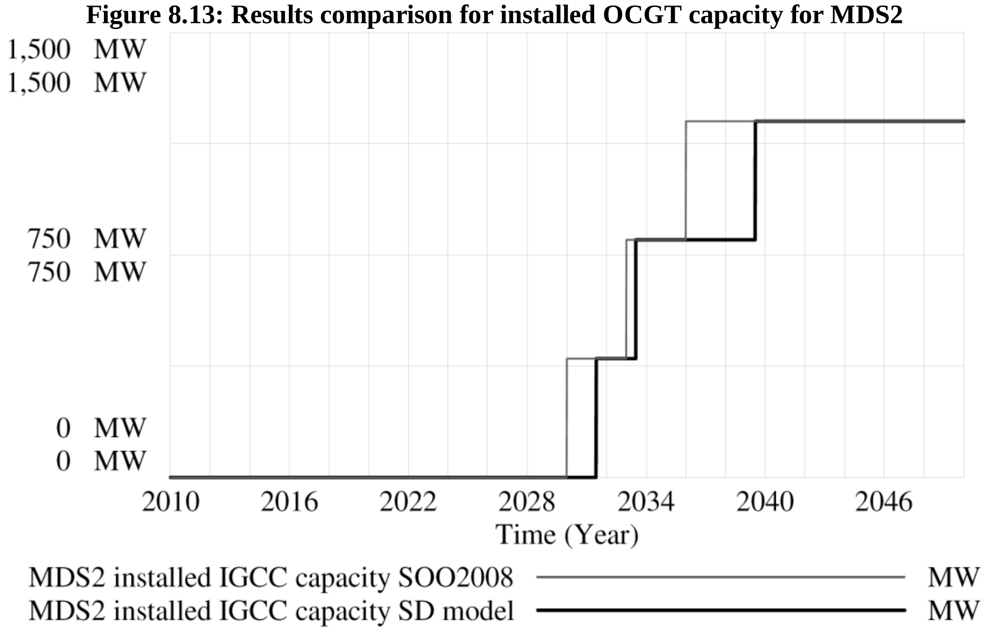


Figure 8.14: Results comparison for installed IGCC capacity for MDS2

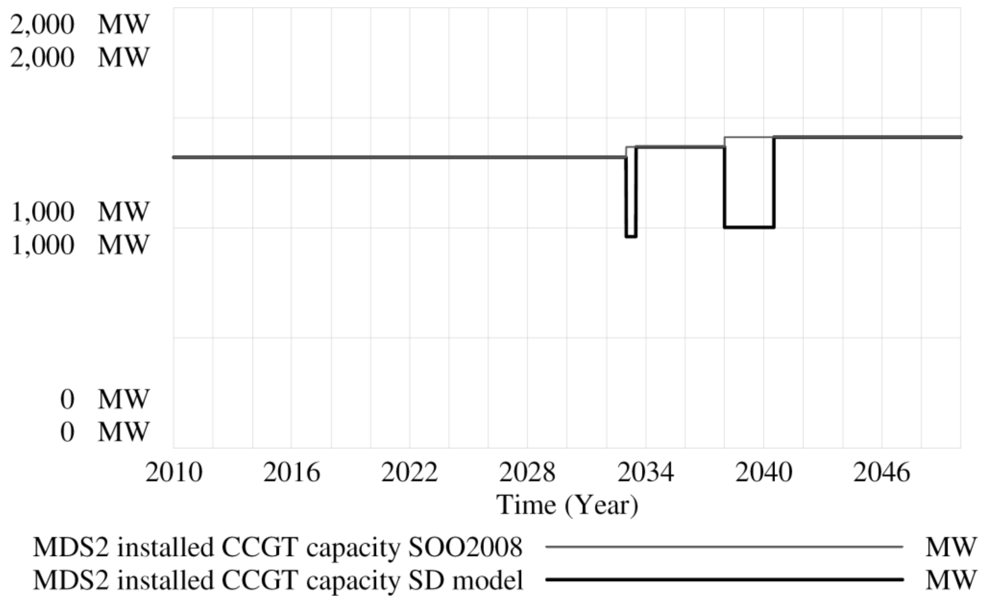


Figure 8.15: Results comparison for installed CCGT capacity for MDS2

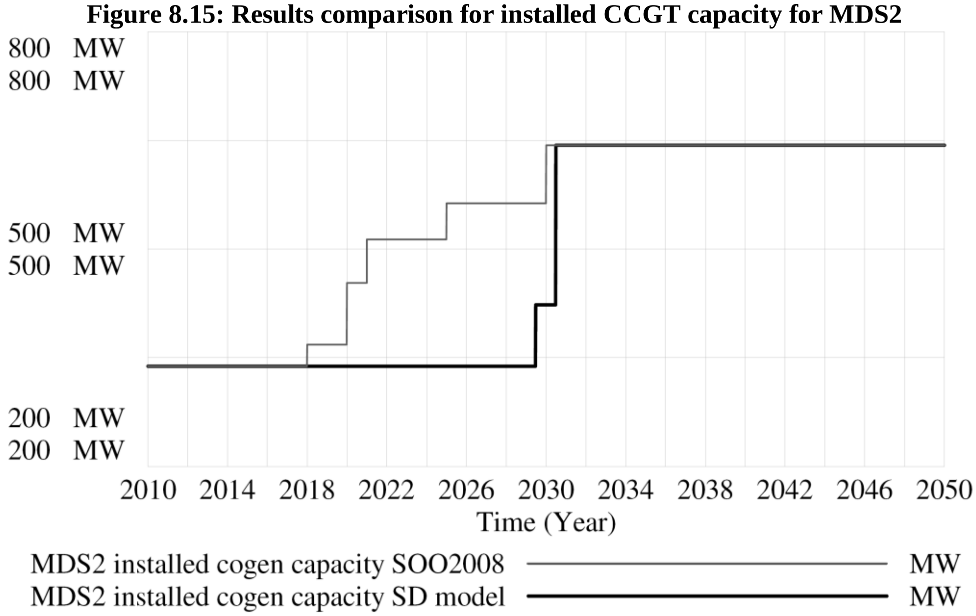


Figure 8.16: Results comparison for installed cogeneration capacity for MDS2

8.1.7 Resultant ECM for MDS2

The calculated ECM (shown in Figure 8.17) for MDS2 indicates that shortages are predicted in the winter of 2038 and 2039. After 2046, new plants need to be built to prevent energy shortages.

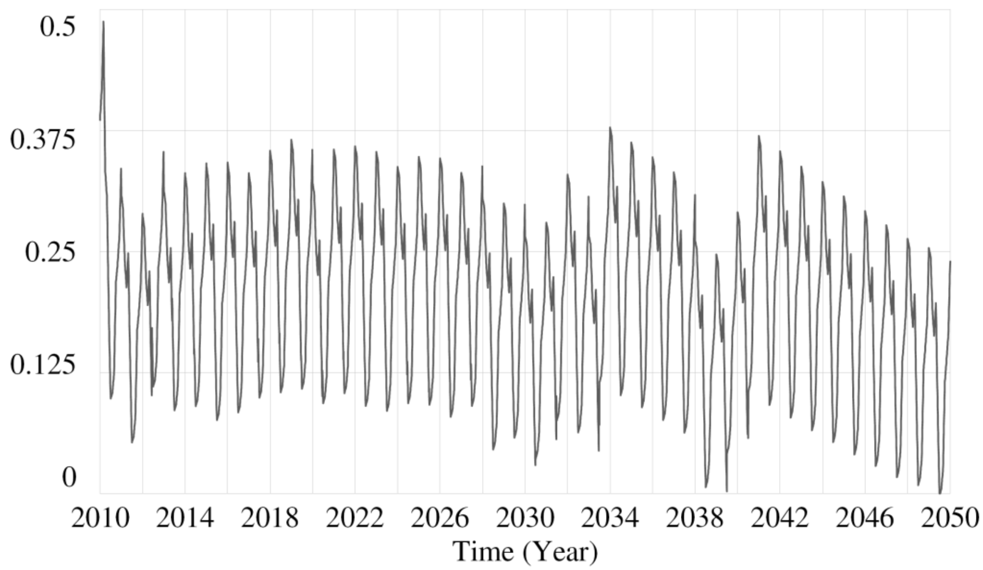


Figure 8.17: Resultant ECM for MDS2

8.1.8 Resultant CM for MDS2

The calculated CM for MDS2 (Figure 8.18) indicates that New Zealand should not have any problem in meeting its peak power demand even in 2039 when the ECM is lowest.

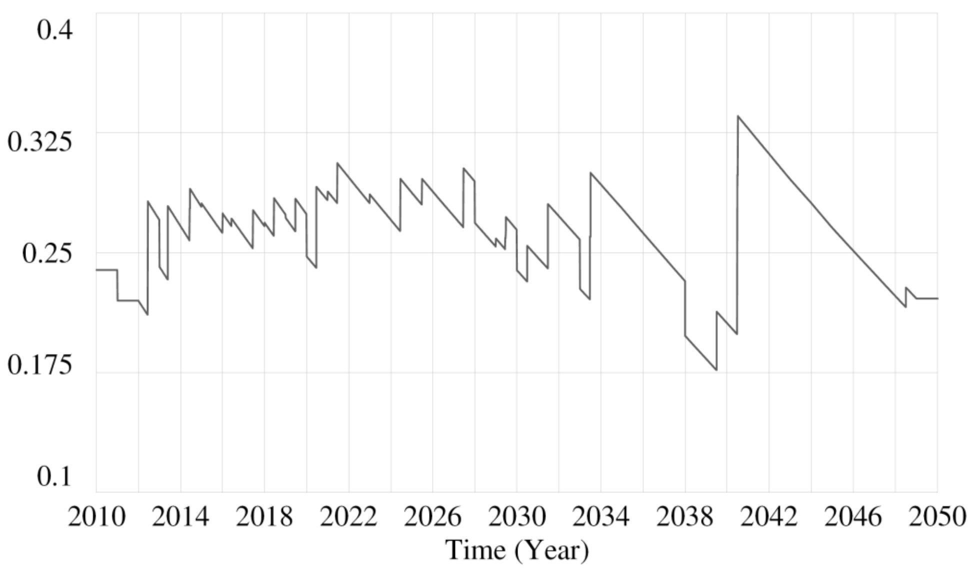


Figure 8.18: Resultant CM for MDS2

8.2 Results comparisons for MDS3 (Medium Renewables)

8.2.1 MDS3 descriptions

The generation mix under MDS3 is with a moderate amount of renewable plants as well as fossil fuel plants. However, base load thermal plants are still restricted until the year 2019 and no new coal plants are built. The carbon and gas price increases at a moderate pace (see Figure 8.19). LNG is allowed to be imported after 2020. Wind and geothermal resources become extensively used. On the demand side, it is assumed that the Tiwai aluminium smelter is phased out around 2020, causing a significant drop in base and peak demand (Figure 8.20 and Figure 8.21). The results from two models for this scenario are shown in the following sections.

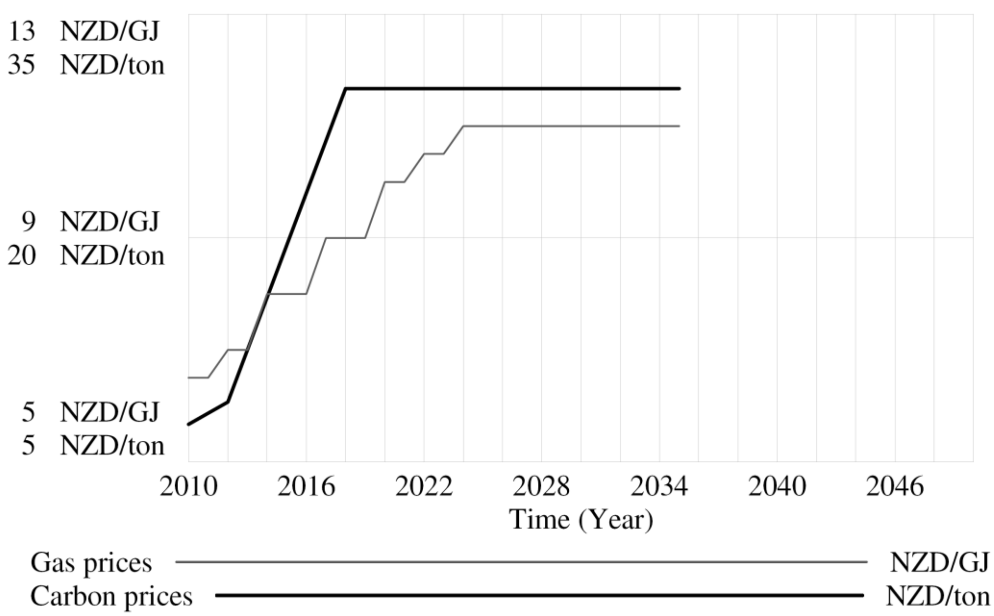


Figure 8.19: Modelled gas and carbon prices for MDS3

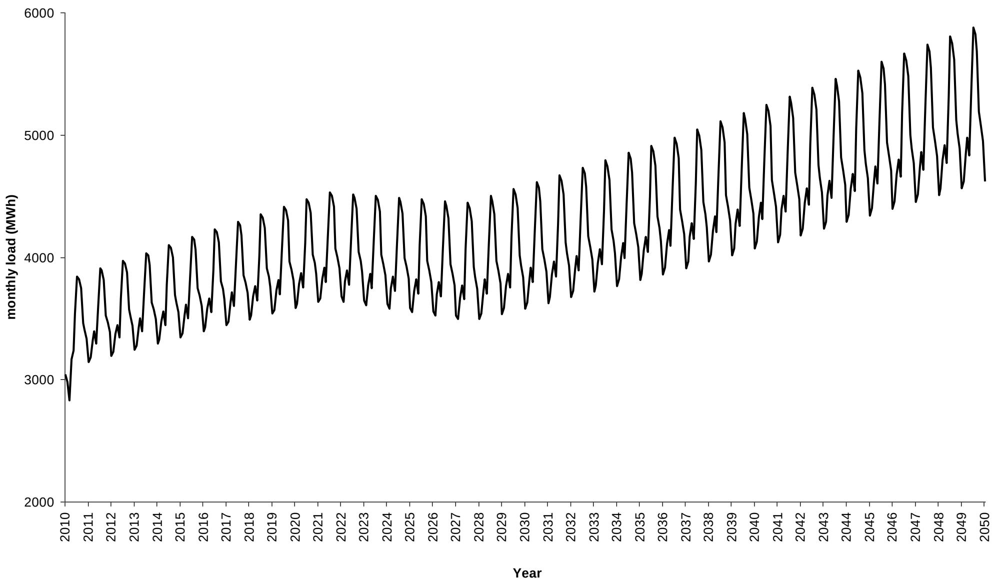


Figure 8.20: Forecasted monthly load consumption for MDS3 (2010 – 2050) (Electricity Commission 2008)

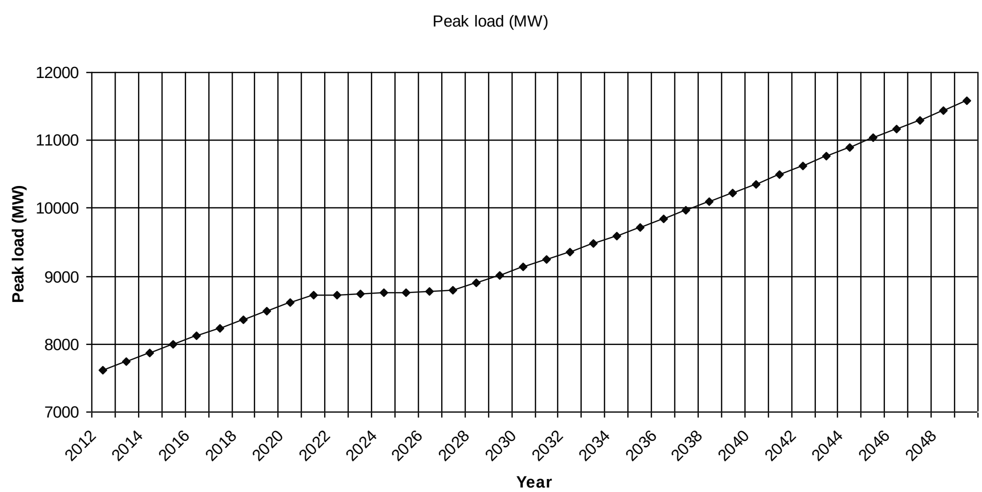


Figure 8.21: Forecasted annual peak load demand for MDS3 (2010 – 2050) (Electricity Commission 2008)

8.2.2 Installed generation capacities comparisons for MDS3

The total installed generation capacities resulted from the two models are shown in Figure 8.22. Due to the reduced demand, the GEM model predicted a stagnant period from 2022 until 2034. The SD model on the other hand, predicted that no new plants will be commissioned despite having old plants retiring, causing a significant drop in the total installed capacity. The bust period is predicted to last for around 7 years from 2026 until

2033. The reduced demand also results in low wholesale market prices from 2020 until 2030 (Figure 8.23). Hence it makes sense for investors not to invest in new plants until the prices are conducive again, after 2032. The installed capacities in the year 2033 are predicted to pick up again, followed by a boom period until 2045. By 2050, all of the scheduled capacities are commissioned. Most of the scheduled capacities (Appendix D3) do not face many delays except for scheduled OCGT plants (Figure 8.24). Some wind (Figure 8.25) and cogeneration (Figure 8.26) plants faces delays during the flat demand growth period. During this period, some old plants get decommissioned and the wholesale market prices begin to increase again as the supply and demand margin narrows.

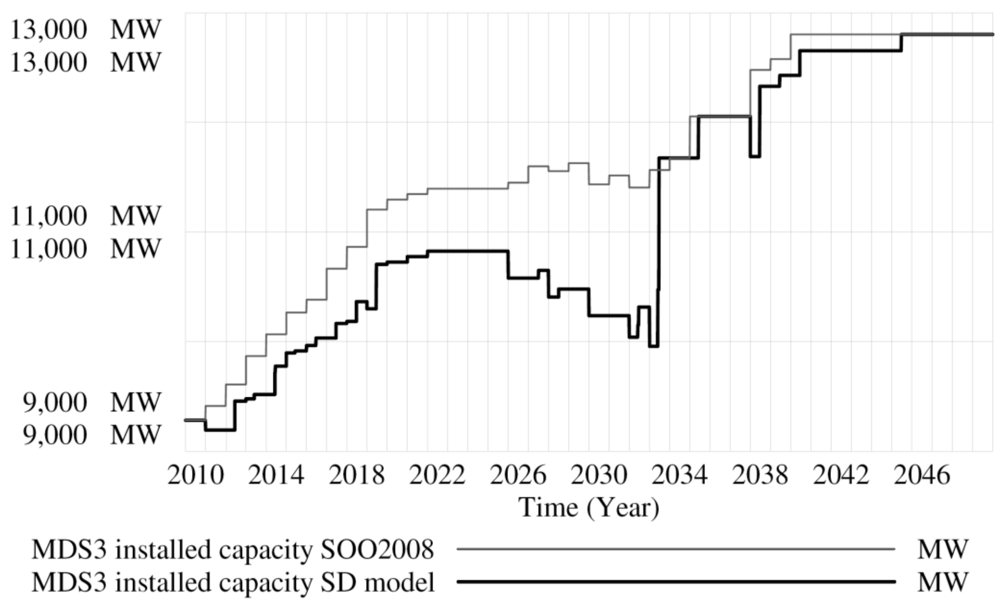


Figure 8.22: Total installed generation capacities comparisons for MDS3

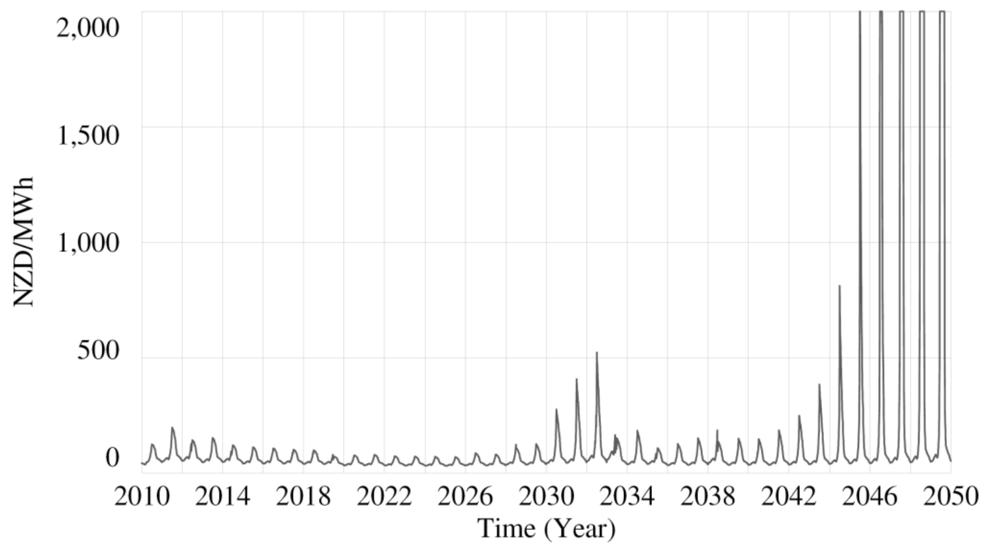


Figure 8.23: Forecasted monthly averaged wholesale electricity price for MDS3

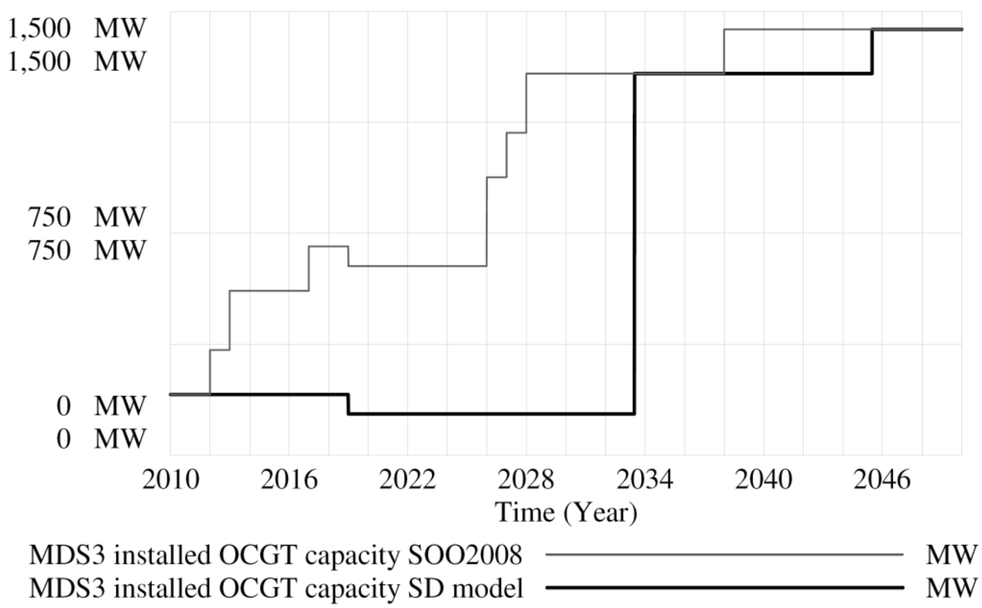


Figure 8.24: Results comparison for installed OCGT capacity for MDS3

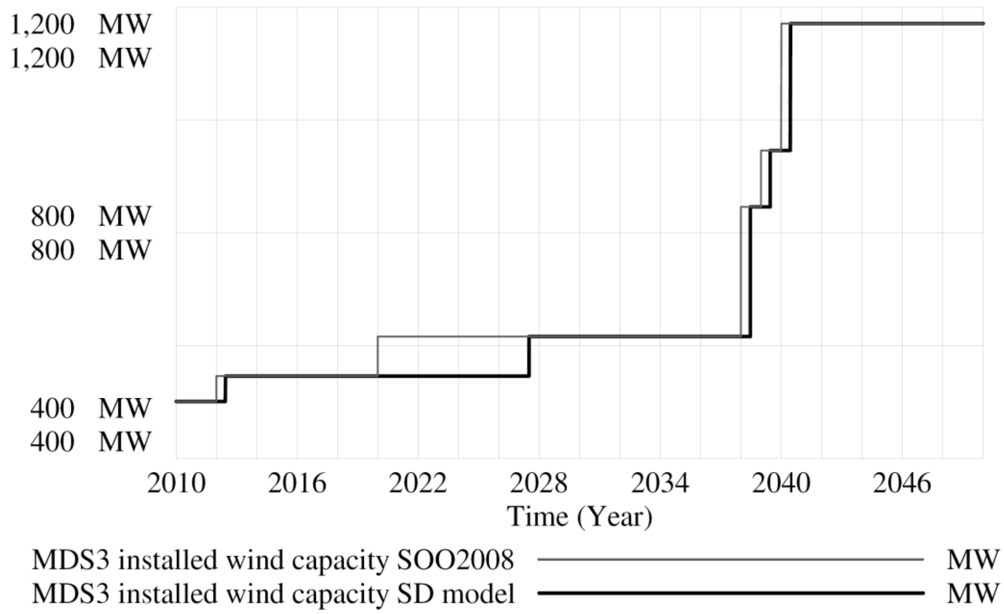


Figure 8.25: Results comparison for installed wind capacity for MDS3

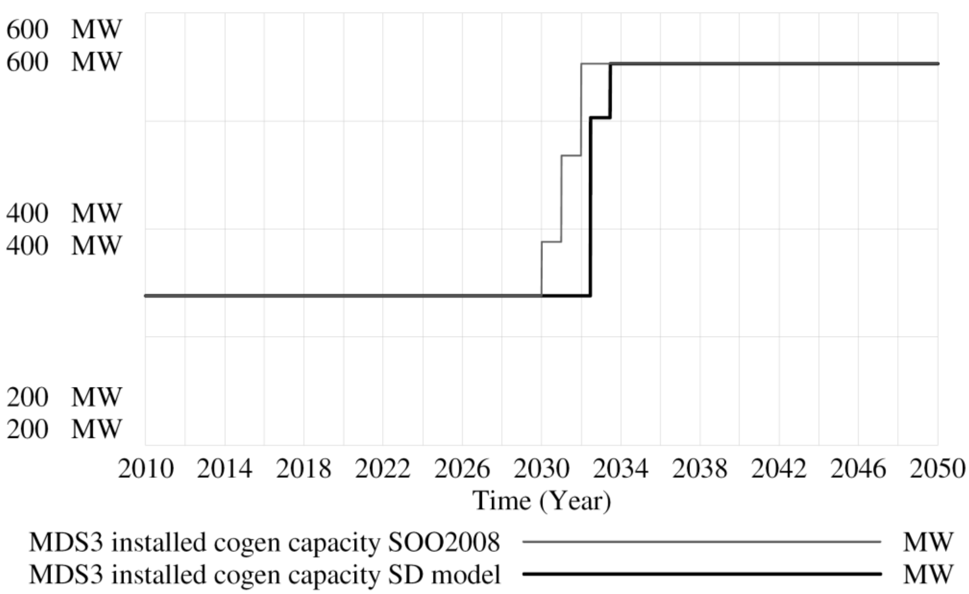


Figure 8.26: Results comparison for installed cogeneration capacity for MDS3

8.2.3 Resultant ECM for MDS3

The calculated ECM from the SD model (Figure 8.27) shows that the ECM became low around 2032, which could bring about energy shortages. The boom period in 2033 increases the ECM for the next few years. After 2042, the ECM becomes low again, indicating the need for new investments.

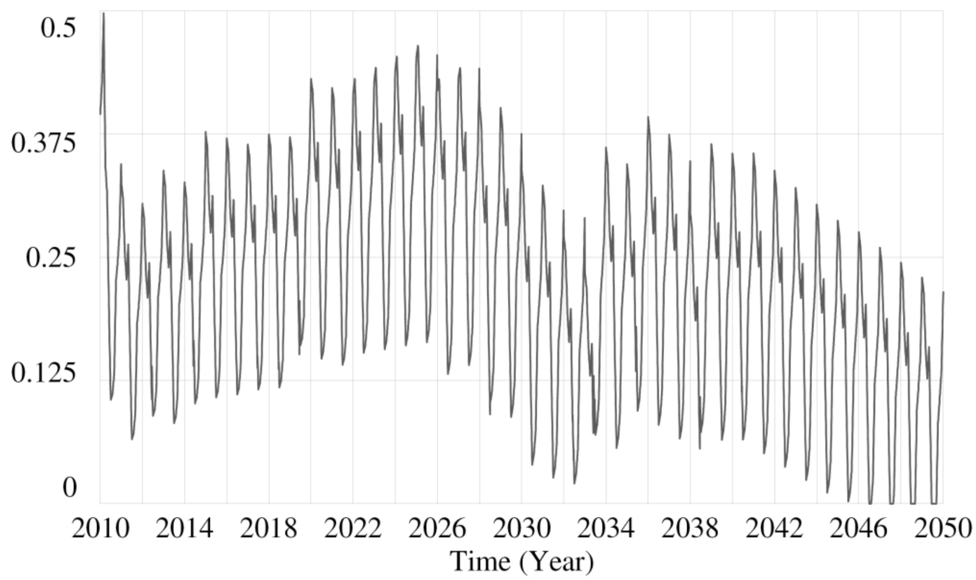


Figure 8.27: Forecasted ECM for MDS3

8.2.4 Resultant CM for MDS3

The calculated CM for MDS3 (Figure 8.28) shows a cycle of bust and boom following the cycle in the installed capacities. The CM value from around 2032-2033 becomes low and poses a threat to system security.

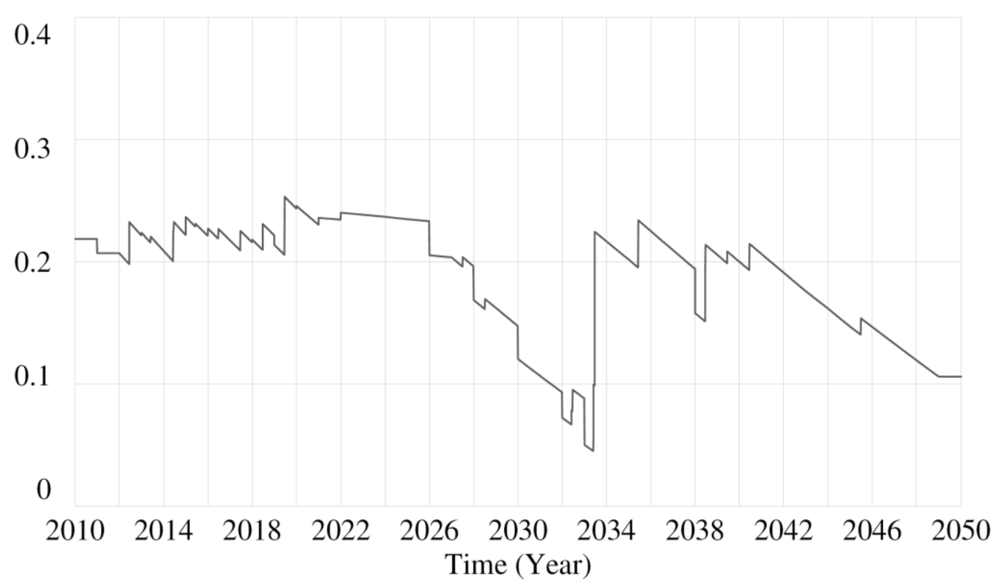


Figure 8.28: Forecasted CM for MDS3

8.3 Results comparisons for MDS4 (Demand Side Participation)

8.3.1 MDS4 descriptions

The MDS4 scenario anticipates intensive demand side participation with high EV uptakes with vehicle to grid technology taking place after 2030. Wind and geothermal will be widely available whereas not many new hydro are consented. The gas and carbon prices are low. The results comparisons for the two models are made in the following sections.

8.3.2 Installed generation capacities comparisons for MDS4

Under MDS4, the SD model predicts some boom and bust cycles in the total installed generation capacities despite the GEM model predicting a steady increase (Figure 8.29). The bust period between 2028 and 2030 results in high wholesale electricity prices (Figure 8.30). Despite the high prices, not all of the scheduled capacities get commissioned by 2050. Looking at the detailed installed capacities, it is observed that the SD model predicts that not all the scheduled coal plants get commissioned by 2050 (Figure 8.31). Most scheduled plants using other technologies faced development delays causing the bust periods (see Figure 8.32-Figure 8.36). The hydro plants are not affected much since there are very few being scheduled (Appendix D4).

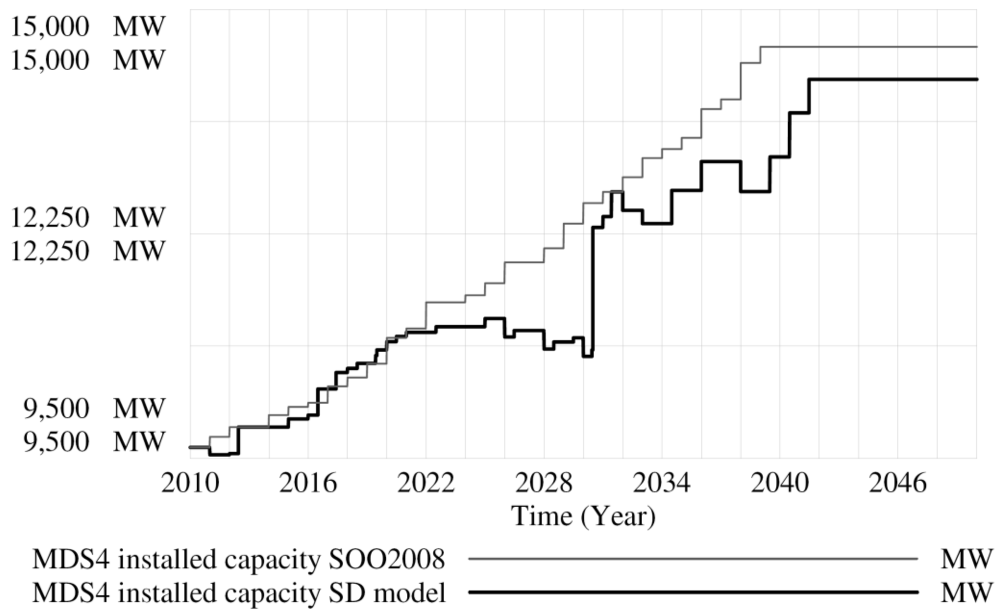


Figure 8.29: Total installed generation capacities comparisons for MDS4

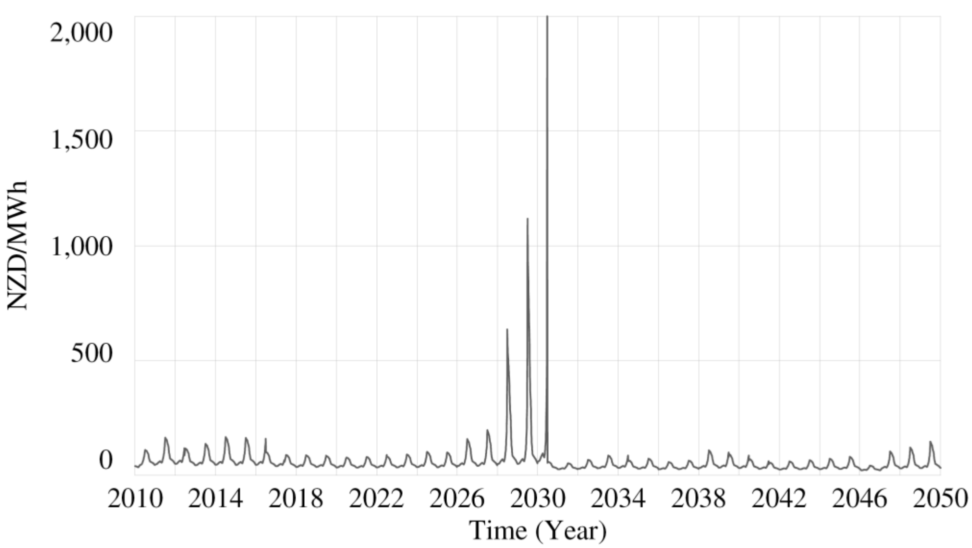


Figure 8.30: Forecasted monthly averaged wholesale electricity price for MDS4

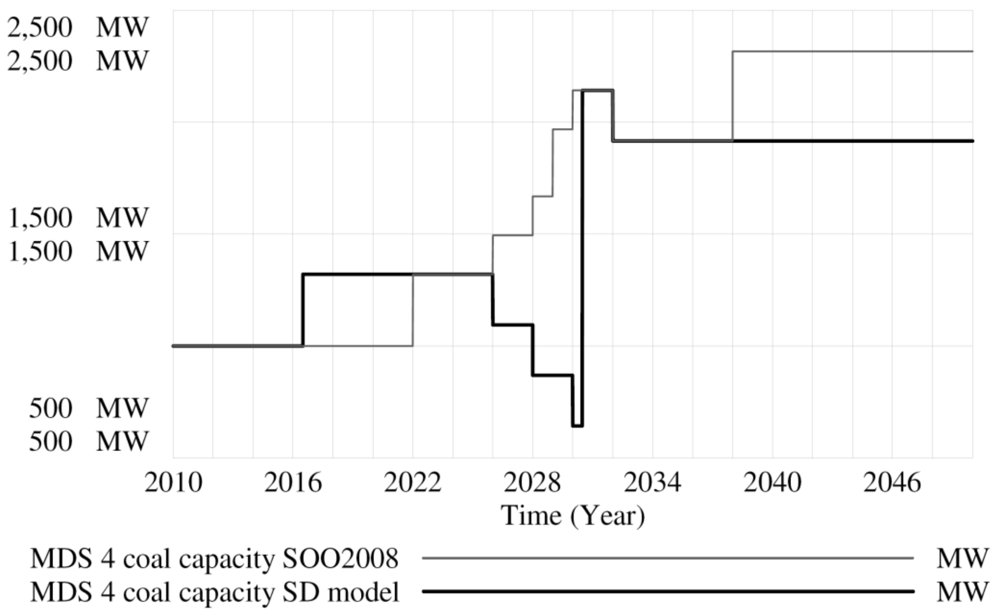


Figure 8.31: Results comparison for installed coal capacity for MDS4

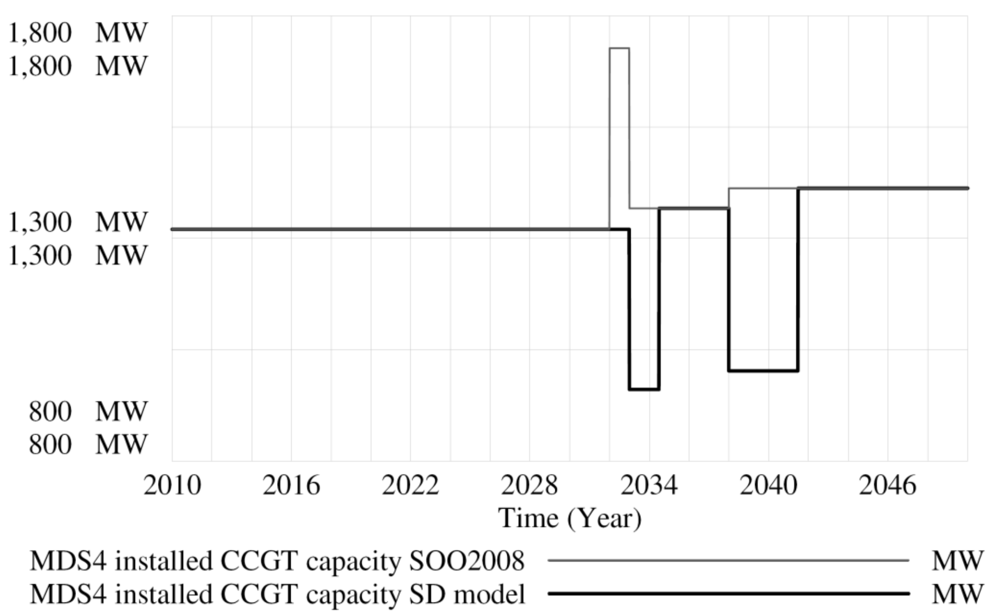


Figure 8.32: Results comparison for installed CCGT capacity for MDS4

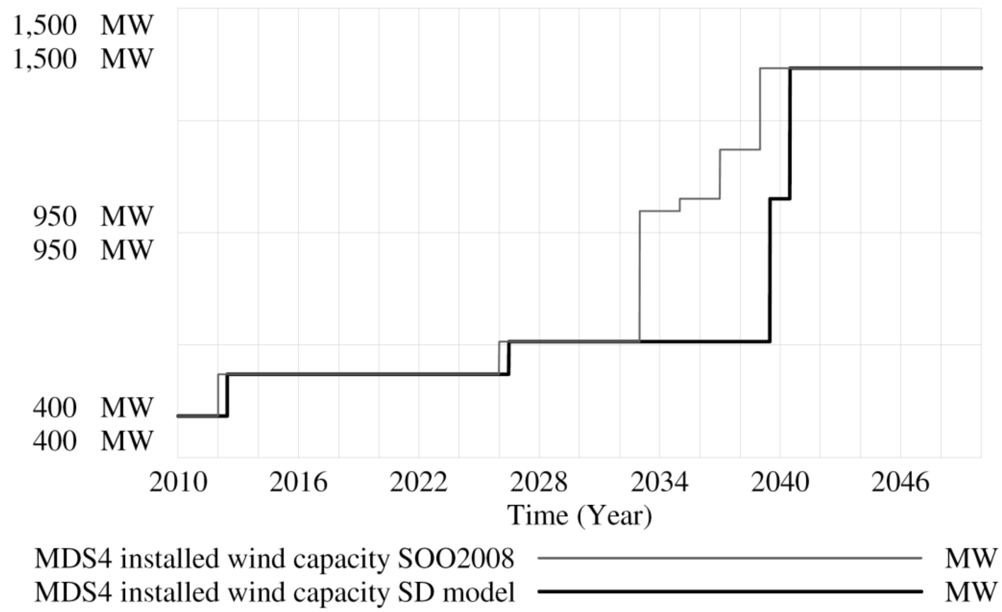


Figure 8.33: Results comparison for installed wind capacity for MDS4

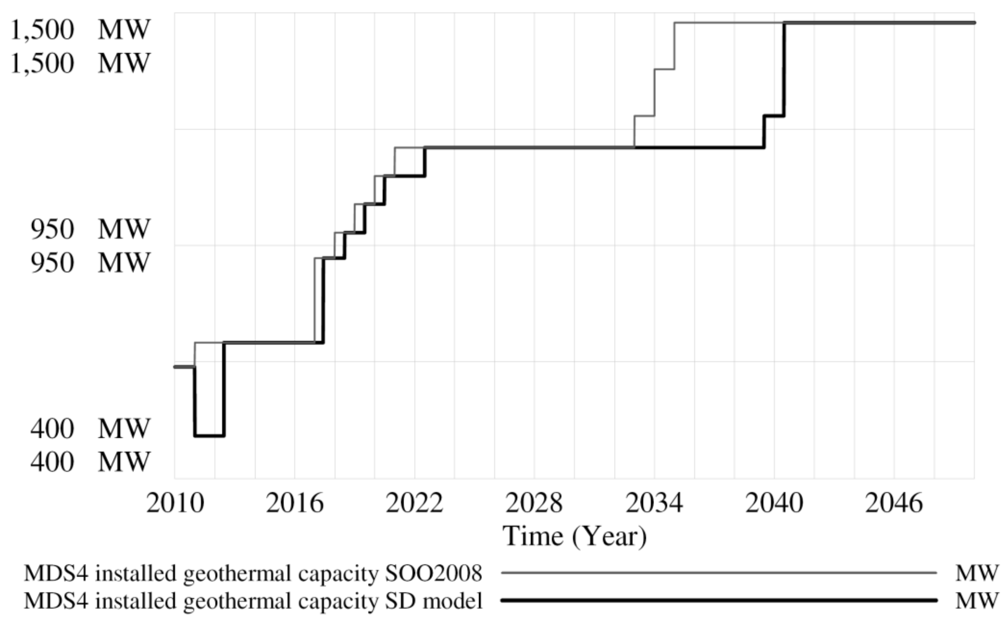


Figure 8.34: Results comparison for installed geothermal capacity for MDS4

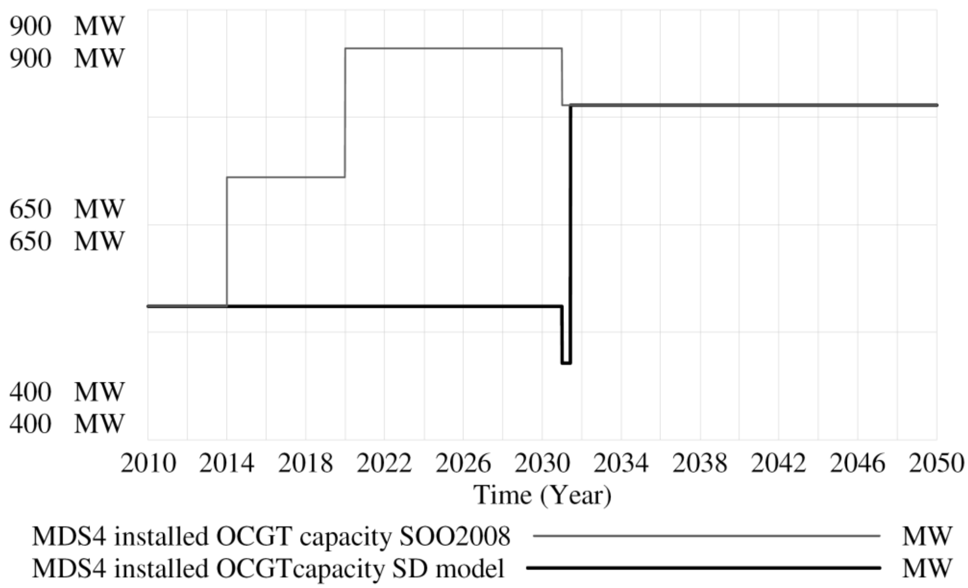


Figure 8.35: Results comparison for installed OCGT capacity for MDS4

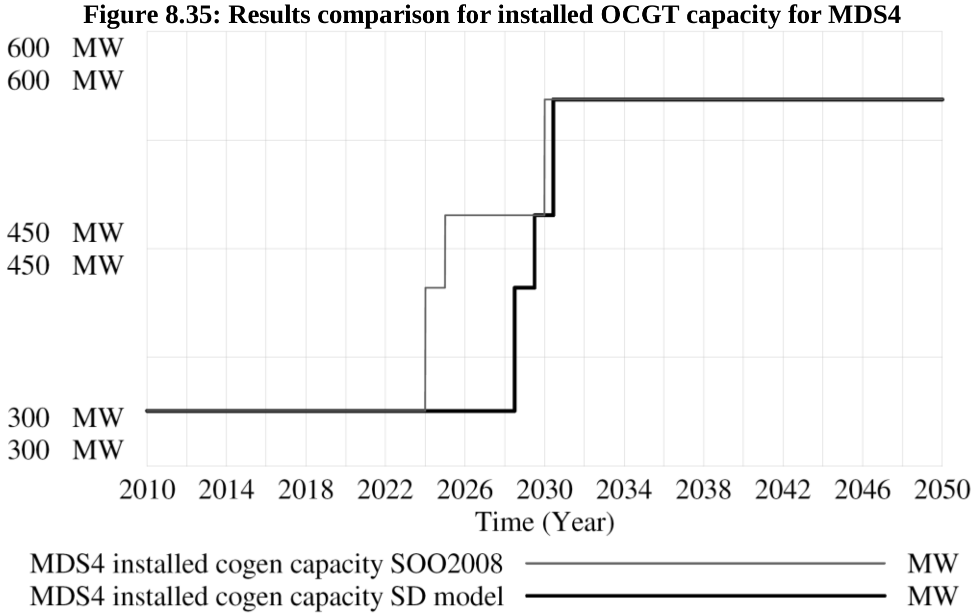


Figure 8.36: Results comparison for installed cogeneration capacity for MDS4

8.3.3 Resultant ECM for MDS4

Besides the seasonal cycles in the ECM, the ECM trend also goes up and down following the boom and bust cycles in the installed generation capacities (Figure 8.37). Low ECM is observed in the winter months of 2028 until 2030, indicating a high likelihood of energy shortages in those years. The successive boom period increases the ECM again until the next bust cycle commences around 2037. The ECM also declines after 2047 indicating the need for new plants to meet the increasing demands.

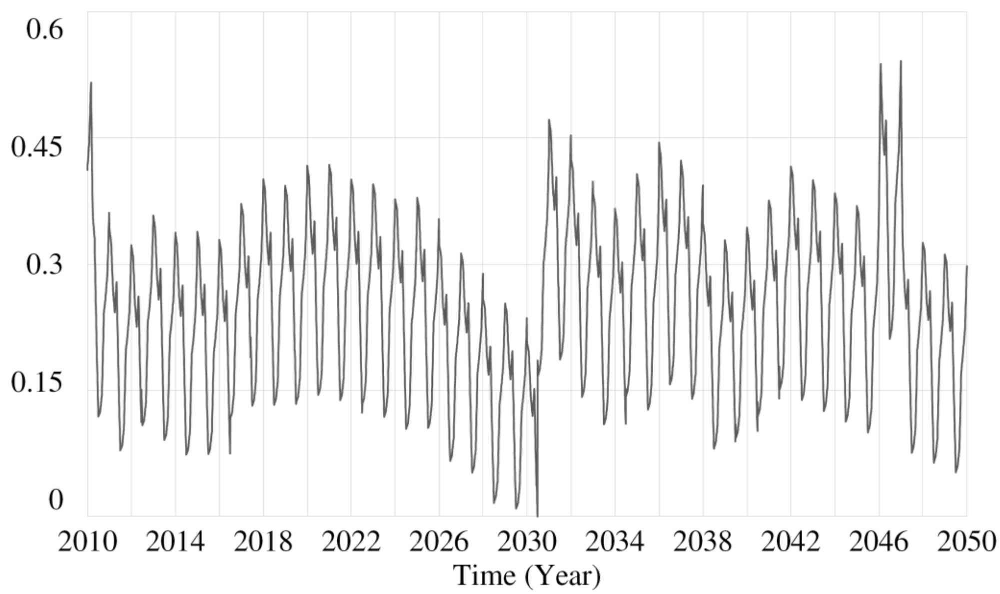


Figure 8.37: Resultant ECM for MDS4

8.3.4 Resultant CM for MDS4

Similar to the ECM, the CM also seems to replicate some cyclic pattern following the cyclic generation capacities (Figure 8.38). The lowest CM of 10% is predicted in 2030, indicating a possibility of a threat to system security.

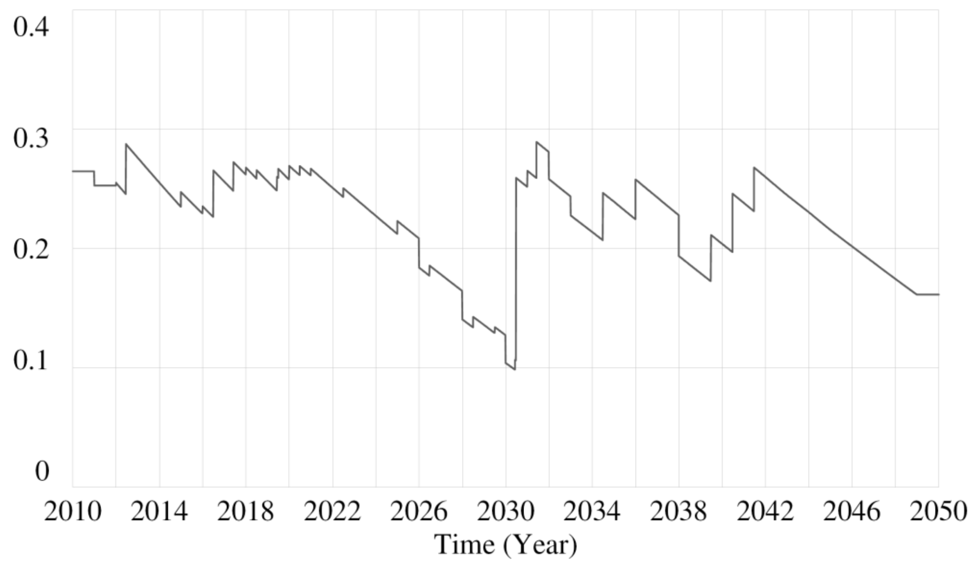


Figure 8.38: Resultant CM for MDS4

8.4 Results comparisons for MDS5 (Gas surplus)

8.4.1 MDS5 descriptions

MDS5 considers a scenario where more gas is discovered in New Zealand resulting in low gas prices. CCGT plants are built to replace existing coal plants. The amount of renewable resources in the generation mix is moderate. The results comparisons for the two models are discussed in the following sections.

8.4.2 Installed generation capacities comparisons for MDS5

The resultant installed generation capacities from the two models (Figure 8.39) do not differ much in the periods of 2010-2013 and 2018-2028. Outside these times, disparities arise from some delayed plants. The delays occur in waiting for the generally low wholesale electricity prices (Figure 8.40) to rise high enough for the plants to recover their cost and gain profits. The plants that face delays are the OCGT, coal and CCGT plants (Figure 8.41-Figure 8.43) whereas other plants get developed without many delays (Appendix D5). All the scheduled capacities get commissioned by 2050.

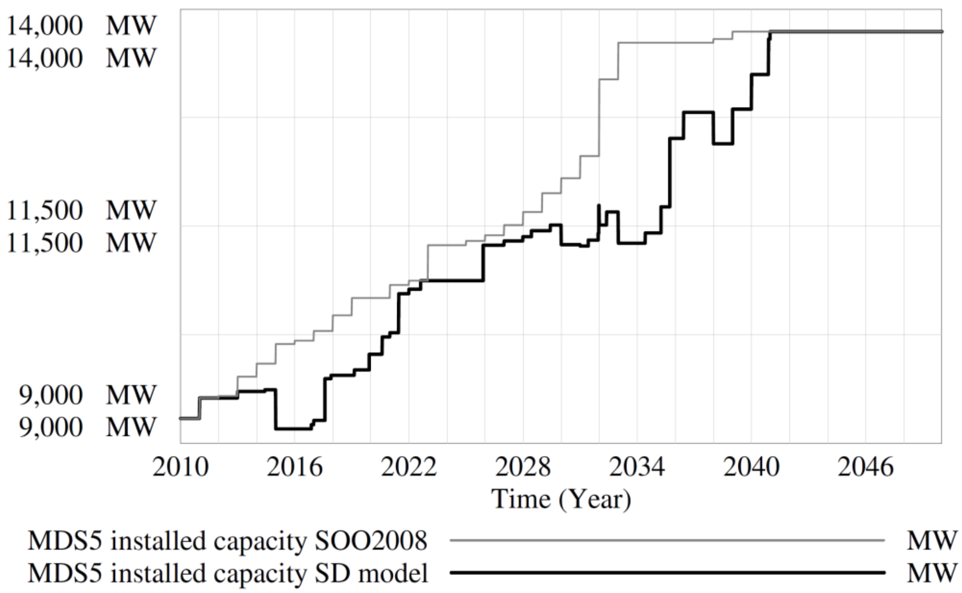


Figure 8.39: Total installed generation capacities comparisons for MDS5

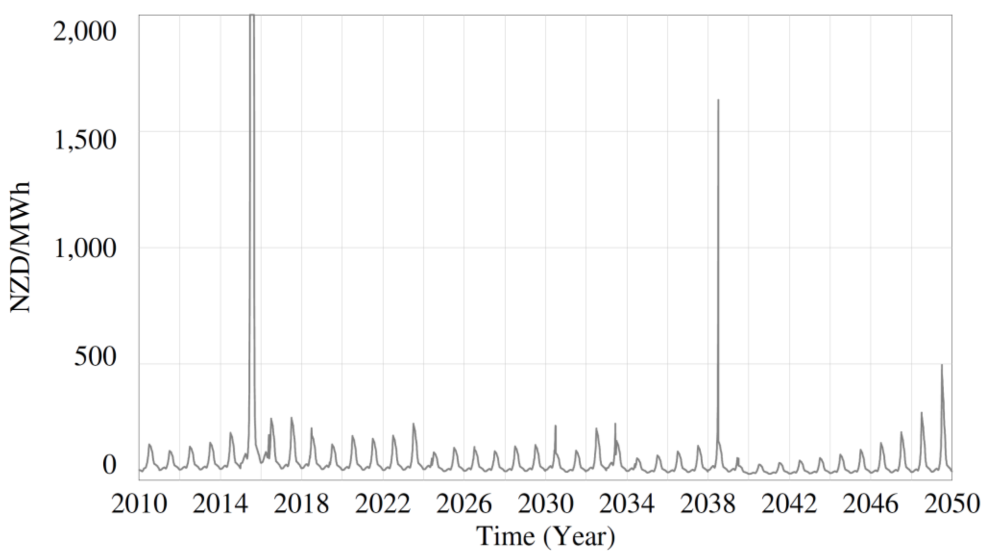


Figure 8.40: Forecasted monthly averaged wholesale electricity price for MDS5

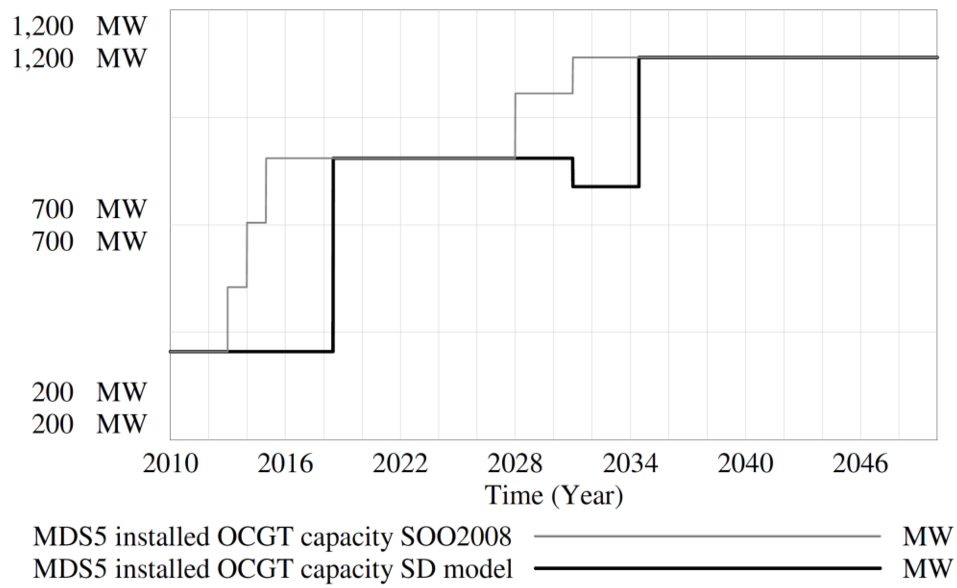


Figure 8.41: Results comparison for installed OCGT capacity for MDS5

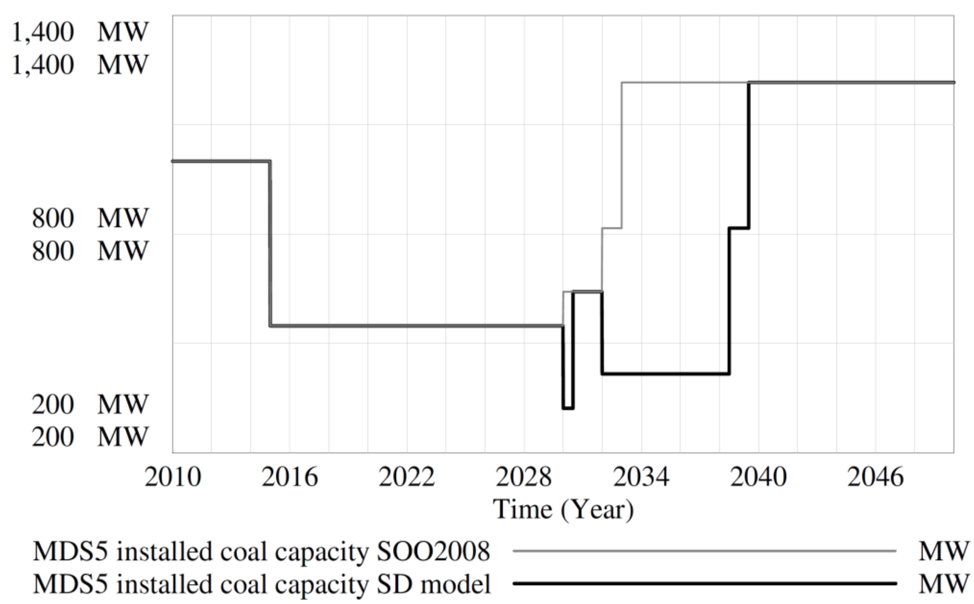


Figure 8.42: Results comparison for installed coal capacity for MDS5

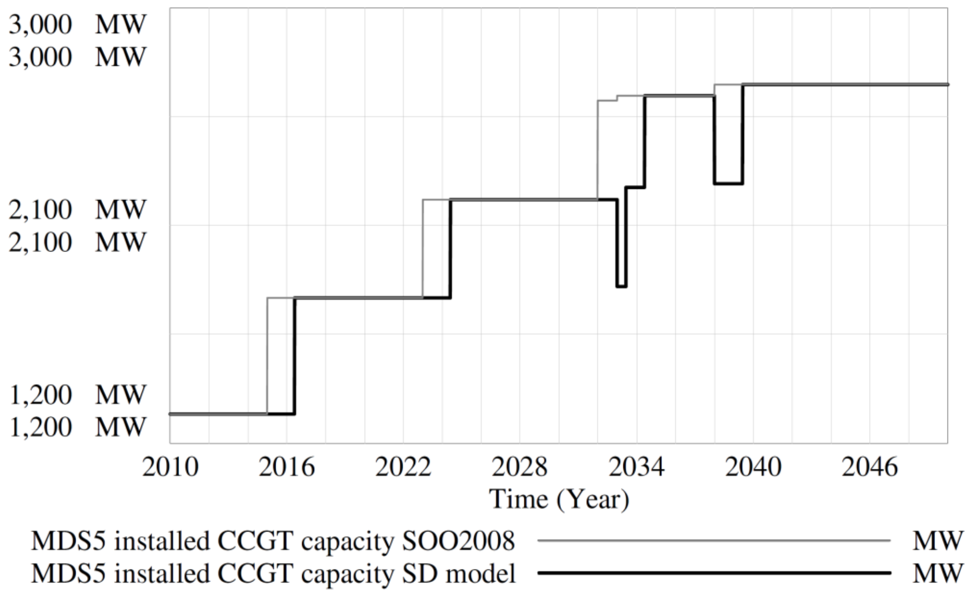


Figure 8.43: Results comparison for installed CCGT capacity for MDS5

8.4.3 Resultant ECM for MDS5

The calculated ECM for MDS5 is shown in Figure 8.44. The ECM remains positive throughout the simulated time but hovers relatively lower during some periods which can cause shortages if some hydro resources are limited.

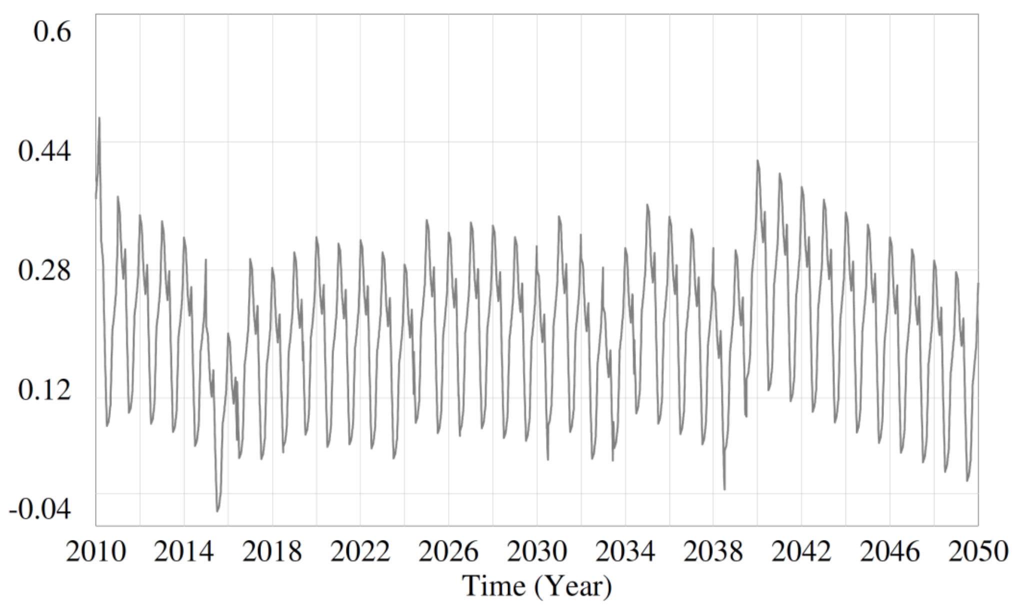


Figure 8.44: Resultant ECM for MDS5

8.4.4 Resultant CM for MDS5

The calculated CM for MDS5 (Figure 8.45) remains above 10% at all times throughout the simulated duration.

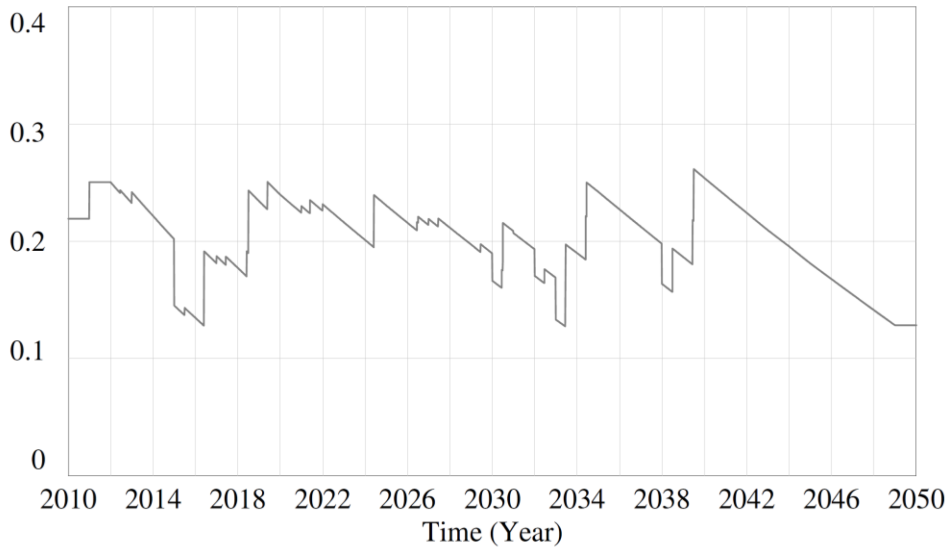


Figure 8.45: Resultant CM for MDS5

8.5 Installed generation capacities comparisons between all scenarios

Looking at the results of the total installed generation capacities from the SD model, it is observed that most of the scheduled capacities get commissioned by 2050 except for those shown in Table 8.1.

Table 8.1: Summary of unmet proposed capacities from all the five scenarios

Scenario	Unmet capacities (MW)	Technology types	Plant's name
Sustainable Path (MDS1)	1100	OCGT	Gas fired OCGT 2, Generic OCGT NI 1-6
Demand-side Participation (MDS4)	400	Coal	Generic coal 5 Huntly stage 1

Under an energy only market, low wholesale electricity prices do not encourage the development of OCGT plants with LRMC. Under all the scenarios, OCGT plants often face delays (Figure 8.13, Figure 8.24, Figure 8.35 and Figure 8.41). In MDS1, the stable low prices do not even allow any OCGT plants to be built (Figure 8.5). The ESI can face problems when there is not enough peaking plants in the total installed capacities because the base load plants are not capable of meeting sharp increases of electricity demand quickly enough. The lack of peakers can also cause blackouts when there is an unexpected outage of a large generator and the void cannot be filled promptly.

As for MDS4, the high demand side participation keeps the electricity prices low enough and avoid the need for a coal power plant to be built until 2050. This is in agreement with the main objective of a demand side participation programme.

Comparing the results of the two models for the five scenarios, it can be observed that the SD model predicts that some plants face delays in their development, whereas the GEM model assumes that the plants get built as scheduled. Unlike the GEM model, the SD model is able to capture the effect of market interactions with generation investments. Investor's decisions to wait for profitable market conditions can thus be taken into account by the SD model.

The SD model is also capable of predicting future generation capacity cycles. The cumulative effects of development delays in power plants can cause a bust period and drive the electricity prices up when the supply and demand margin declines. The bust period is then followed by a boom period where generation companies rush to build new plants to meet the demand. Boom and bust cycles have been observed in other commodity markets such as real estates. However, the cycles in generation capacity are more pronounced when there are power plants of large lumpy capacities, enormous capital investment and long lead time. Comparing the results for the different scenarios, the cyclic patterns in installed capacities are more obvious when the plants are large capacity thermal plants with high LRMCs (MDS3 and MDS4). Having more small renewable plants (like in MDS1 and MDS2) produces less cyclic patterns as the LRMCs are lower and hence the profit can be recovered easily with relatively lower spot market prices.

8.6 ECM comparisons between all scenarios

It can be argued that capacity cycles are normal under a market environment to ensure that investments are made efficiently in meeting demands. However, a severe bust period in the generation capacity may cause severe electricity shortages that can be detrimental to the economy and cause inconvenience to consumers. The variable ECM provides a good indicator in measuring a potential electricity shortage. The resultant ECMs for all five scenarios are summarised in Table 8.2. The following criteria are used in determining the possibility of future energy shortages:

- Shortages are possible if ECM<5%.
- Shortages occur when ECM<0

Table 8.2: Summary of ECM statistics for the five scenarios

Scenario	ECM statistics (%)			Shortage occurs?
	Min	Max	Mean	
Sustainable Path (MDS1)	1.53	52.01	19.56	Possibly in 2019-2022, 2024-2026, 2028, 2032 and 2039-2041
South Island Surplus (MDS2)	-0.29	48.74	20.28	Possibly in 2028, 2031, 2038 and 2039. Yes in 2050 if no new plants are scheduled after 2040
Medium Renewables (MDS3)	-4.59	49.76	22.17	Possibly in winter 2031- 2033 and after 2041. Yes after 2046 if no new plants are scheduled after 2040
Demand-side Participation (MDS4)	-0.33	54.12	24.53	Possibly from winter of 2028 until 2030. Yes in 2031
High Gas Recovery (MDS5)	1.60	46.99	20.31	Possibly in 2016, 2017, 2030, 2038-2040

From Table 8.2, the highest possibility for shortages are observed for MDS3 and MDS4 where distinct boom and bust cycles are observed.

8.7 CM comparisons between all scenarios

The capacity margin measures the system ability to meet peak demands. Unlike load consumptions which are expected to rise in time, peak demand timings are random and its values are more difficult to predict. Hence, a system is usually designed to have a certain amount of capacity margin to meet peak demands (e.g. 15%). Table 8.3 summarises the calculated CM values by the SD model for all five scenarios.

The following criteria are used in determining the possibility of future supply security risk:

- Security risk likely to occur if CM<15%.
- Security risk occurs when CM<0

Table 8.3: Summary of CM statistics for the five scenarios

Scenario	CM statistics (%)			Security risk occurs?
	Min	Max	Mean	
Sustainable Path (MDS1)	16.28	38.36	28.39	No
South Island Surplus (MDS2)	17.64	33.54	26.18	No
Medium Renewables (MDS3)	4.49	25.32	18.87	Possibly from 2030-2033 and 2045 if no new plants are scheduled after 2040
Demand-side Participation (MDS4)	9.85	28.93	22.44	Possibly between 2028 and 2031
High Gas Recovery (MDS5)	12.83	25.50	20.04	Possibly in 2015, 2038 and 2040

From Table 8.3, it can be observed that security risks are higher for MDS3 and MDS4 where obvious capacity boom and bust cycles are observed.

8.8 Chapter summary

From the results comparisons of the GEM and SD model under the five scenarios, it can be observed that the SD model is able to capture the effect of market interactions with generation investments. Due to this feature, the SD model is capable of predicting the following:

- future plant development delays due to investment decisions
- future generation capacity cycles

From the ECM calculated in the SD model, it can be observed that boom and bust cycles can cause future energy shortages in New Zealand. As for the system security, even though the resultant CM values remain positive throughout the simulated duration, higher security risks are posed when boom and bust cycles are observed.

Boom and bust cycles are more pronounced when the generation mix are dominated by plants of large capacity and high LRMC. For New Zealand, it seems like having more small renewable plants (like in MDS1 and MDS2) produces less generation capacity cycles. However, under these scenarios, NZ might face shortages under some weather conditions, as discussed in Chapter 9.

9 Sensitivity Analyses on the SD Model

A sensitivity analysis is a study of how the outputs of a model change with the variations of its inputs. To analyse the SD model results further, the model inputs were varied to study their impacts on its outputs. The inputs considered in these sensitivity analyses are shown in Table 9.1. The table also provides the reasons why these inputs were considered.

Table 9.1: Model inputs analysed in the sensitivity analyses

Model inputs	Analysis motivation
(i) Delays in plant development	Delays during long term development projects are common
(ii) Forecasted load demand	This model uses long term load forecasts made by the EC. The SOO2008 states that their forecasts are subject to 80% confidence limits with 10% chance of the forecasted demand being higher or lower
(iii) Weather conditions	Weather conditions affect the availability of renewable resources. Historically, New Zealand hydro resources have been affected by La Niña occurrences

By varying these inputs, their impacts on installed generation capacities, ECM and CM were analysed. These inputs are varied one at a time so that their impacts on the outputs can be clearly observed. When an input is varied, the two other model inputs are assumed to be at their baseline values. The full simulation results for these sensitivity analyses are shown in Appendix E. The following sections discuss how the input variations affect the SD model outputs.

9.1 Impacts of plant development delays

During power plant development, delays can arise at various stages for various reasons. For example, a delay can occur at the approval stage if a plant's resource consent application (in accordance with the RMA) gets rejected. The plant will then need to undergo the resource consent application stage all over again. The impacts of delays are analysed by applying medium and long delays at each plant development stage as shown in Table 9.2.

The baseline development duration is the fastest time a type of plant can get developed. Medium delays commonly occur whereas long delays may happen in some circumstances, e.g. when there is public opposition to a project. The SD model outputs for the baseline plant development phase are the same as shown previously in Chapter 8. The results featured in this section are only for the medium and long delays.

Table 9.2: Variations applied to plant development durations to study the impacts of delays

Plant type	Plant lead time (year)			Planning (year)			Approval (year)			Construction (year)		
	Base	Medium delay	Long delay	Base	Medium delay	Long delay	Base	Medium delay	Long delay	Base	Medium delay	Long delay
Hydro	5	7.5	10	1	2	3	1	1.5	2	3	4	5
Coal/IGCC	4	5.5	7	1	1.5	2	1	1.5	2	2	2.5	3
CCGT	3	5.5	7	0.5	1.5	2	0.5	1.5	2	2	2.5	3
OCGT	2	5	7	0.5	1.5	2	0.5	1.5	2	1	2	3
Wind	3	5.5	8	1	2	3	1	1.5	2	1	2	3
Geothermal	3	5.5	8	1	2	3	1	1.5	2	1	2	3
Cogeneration	3	5	7	1	2	3	1	1.5	2	1	1.5	2
Pumped storage	8	10.5	13	1	2	3	2	2.5	3	5	6	7
Wave	5	6.5	8	1	1.5	2	1	1.5	2	3	3.5	4

9.1.1 Impacts on installed generation capacities

After applying the different delays to plant development, their impacts on the total installed generation capacities for the different MDS can be observed as per Appendix E1. The results indicate the following:

i. Depending on the scenarios and timing of the scheduled plant, delays can affect whether a scheduled power plant gets commissioned or not. In the long run, this affects the total installed generation capacities.

ii. The various delays act as damping factors on the boom and bust pattern of the total installed generation capacities.

These findings are elaborated further as follows. For MDS1, under the baseline case, none of the OCGT plants get commissioned, as shown in section 8.1.1. From Figure 9.1, it can be observed that for MDS1, plant development delays cause all the scheduled capacities to get commissioned. The reason is because delays cause the margin between supply and demand to become larger and hence push the wholesale prices up (Figure 9.2) and allow all the scheduled plants to get developed.

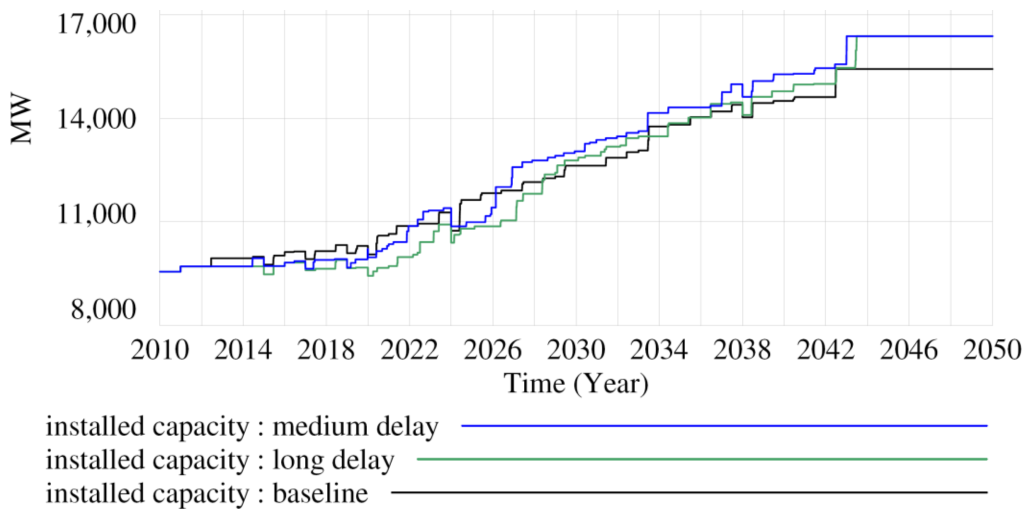


Figure 9.1: Impacts of delays on the installed capacities for MDS1

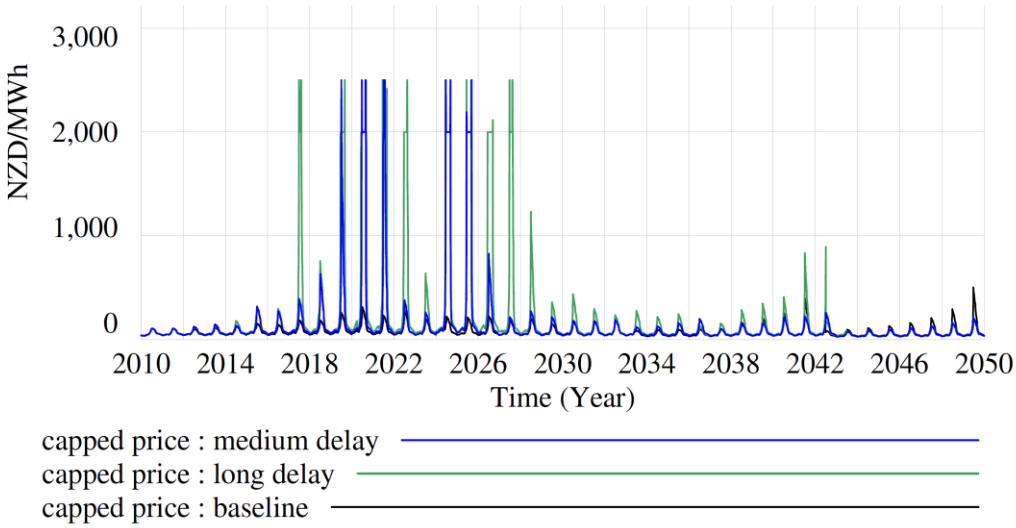


Figure 9.2: Forecasted prices under various delays for MDS1

However, the opposite happens for MDS2 (see Figure 9.3 and Figure 9.4). When delays happen, one of the scheduled OCGT plants does not get commissioned. The plant that is predicted not to get commissioned is the 150MW generic OCGT NI 7 (with a LRMC of NZD302/MWh) that was scheduled to be commissioned by 2038. Based on the typical lead time for OCGT plants, if the OCGT NI 7 plant is to be commissioned by 2038, it needs to be proposed at the latest by 2036. The reason why it does not get commissioned is because the delays have caused price spikes to occur around 2033-2034 (see Figure 9.5) causing many plants to be commissioned by 2037 (see Figure 9.3). By then, adequate plants have been built, leading to stable prices around that time. However, for the baseline case, the lower amounts of installed capacities from 2038-2042 push up the price (Figure 9.5) around that time and hence allow the 150MW plant to be built.

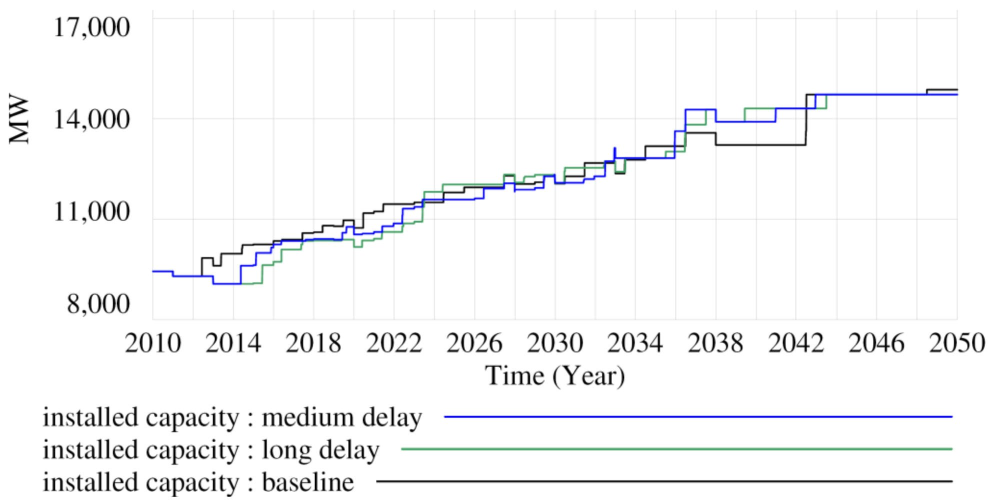


Figure 9.3: Impacts of delays on the installed capacities for MDS2

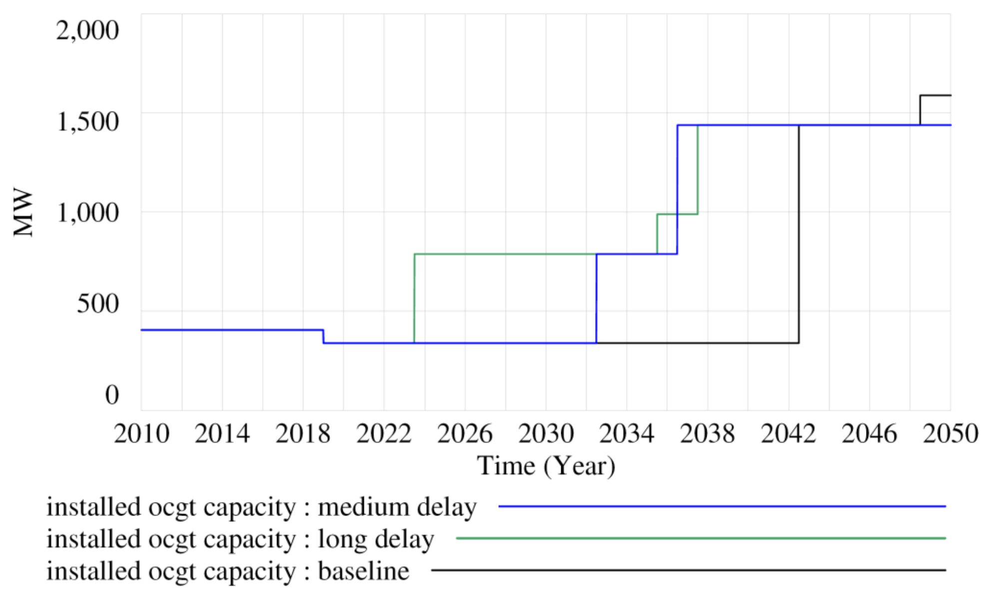


Figure 9.4: Impacts of delays on the OCGT installed capacities for MDS2

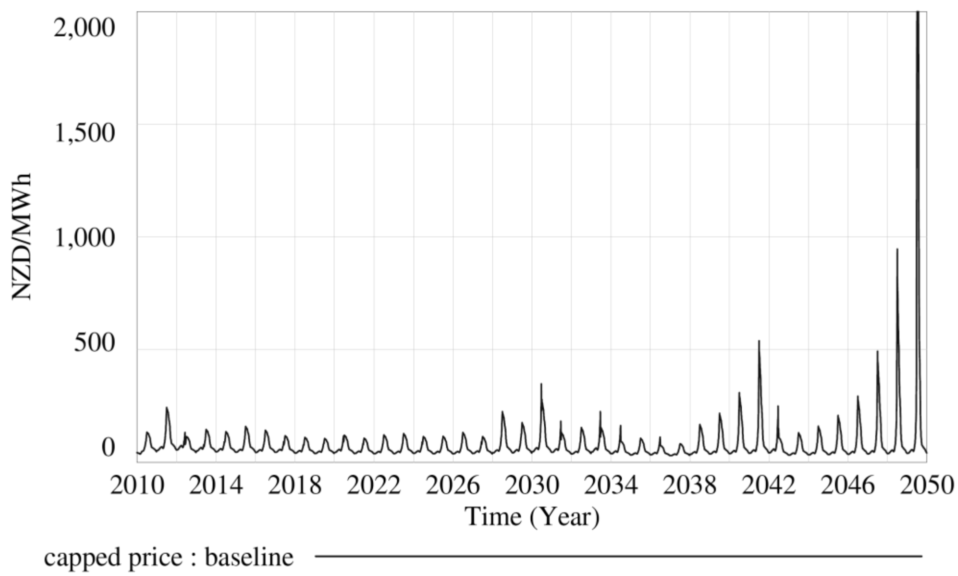


Figure 9.5: Forecasted price for baseline case under MDS2

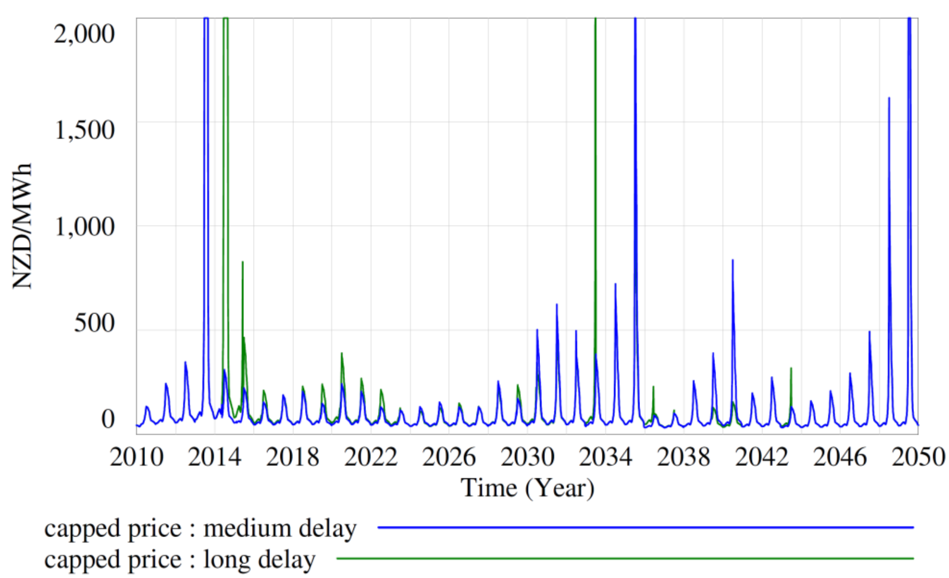


Figure 9.6: Forecasted prices under various delays for MDS2

As discussed in section 8.1.1, boom and bust patterns can be observed under MDS3 and MDS4 where there are more large capacity thermal plants being scheduled. Plant development delays seem to have damping effects on the predicted boom and bust cycles (Figure 9.7). The same effects can be observed under MDS4 (Figure 9.8). Under MDS5 (Figure 9.9), boom and bust cycles can be observed more clearly when delays occur, even though the cycles are not so obvious for the baseline case.

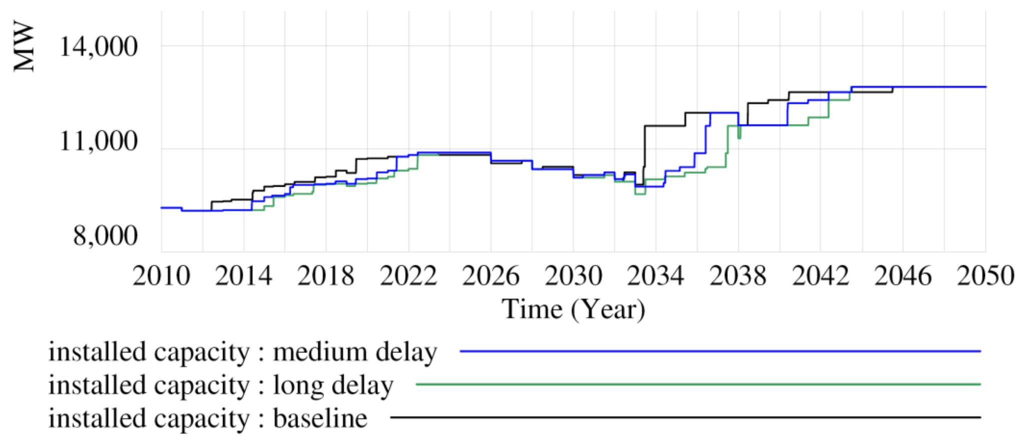


Figure 9.7: Impacts of delays on the installed capacities for MDS3

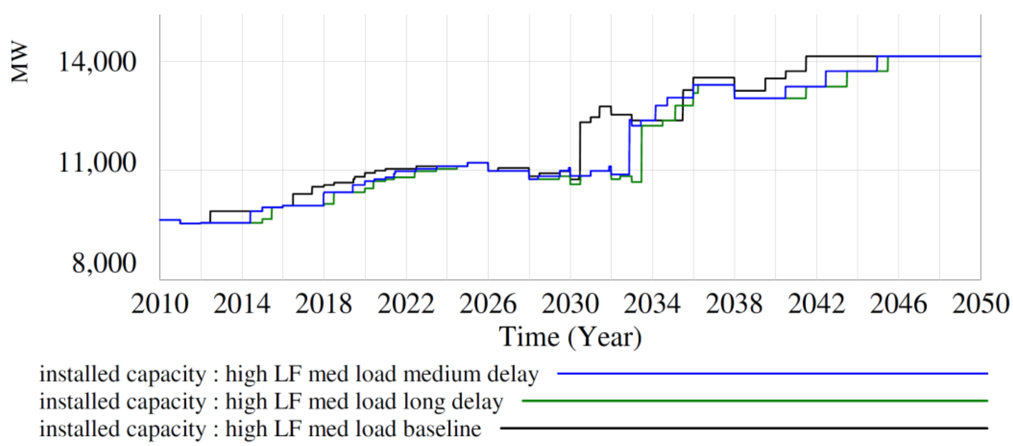


Figure 9.8: Impacts of delays on the installed capacities for MDS4

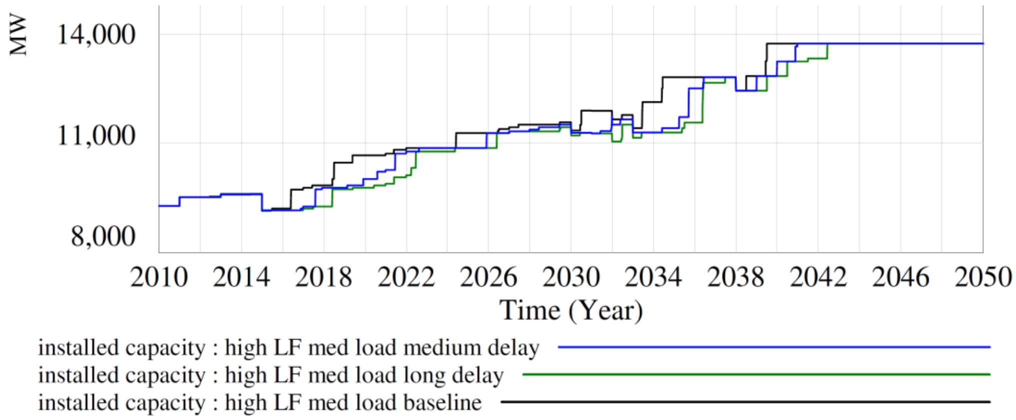


Figure 9.9: Impacts of delays on the installed capacities for MDS5

The damping effects of plant development delays are elaborated further as follows. Figure 9.10-Figure 9.12 show examples from MDS3 on the damping effects caused by plant development delays on the total installed capacities. The total capacities in each figure are compared to the scheduled capacities in the SOO2008 to make the damping effects more visible. By comparing the three figures, it can be observed that delays cause the boom and bust cycles to be more obvious, i.e. the longer the delay, the more capacity trends became less damped. Similar observations can be made for MDS5. Figure 9.13 and Figure 9.14 show the delay effects on the installed capacities under MDS5. For the baseline case, the capacity cycles are not so obvious (Figure 9.13). Comparing this with Figure 9.14, it can be observed that the delays cause the boom and bust cycles in the capacity to become less damped and hence more pronounced.

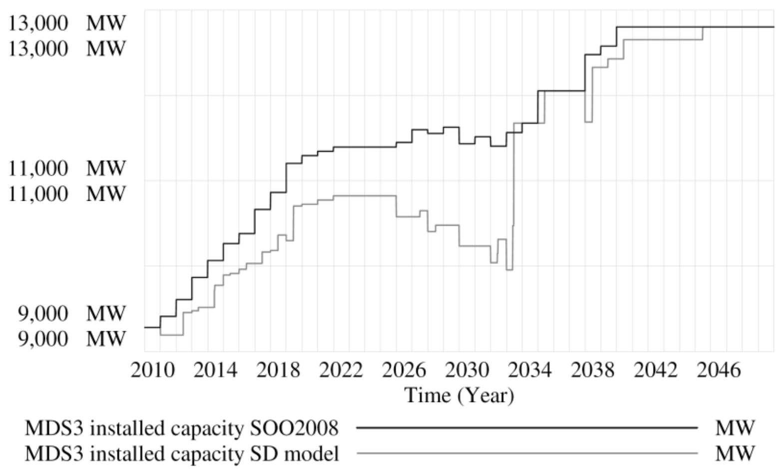


Figure 9.10: Predicted total installed capacity under MDS3 for baseline case

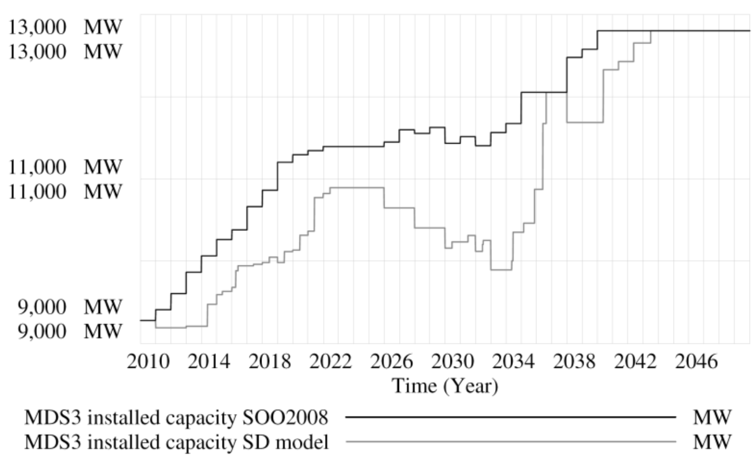


Figure 9.11: Predicted total installed capacity under MDS3 in the case of medium delay

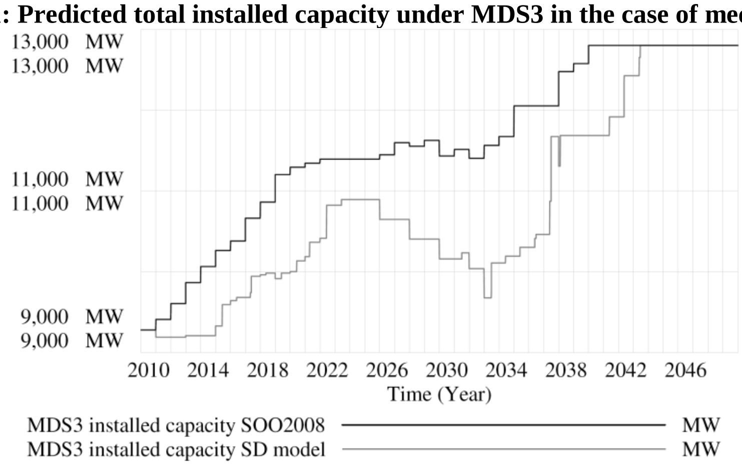


Figure 9.12: Predicted total installed capacity under MDS3 in the case of long delay

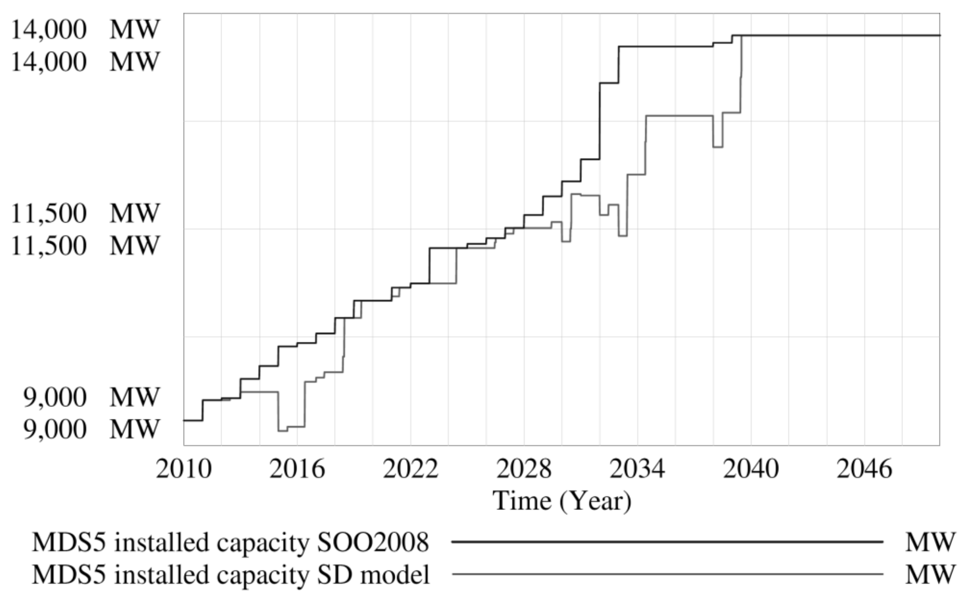


Figure 9.13: Predicted total installed capacity under MDS5 for baseline case

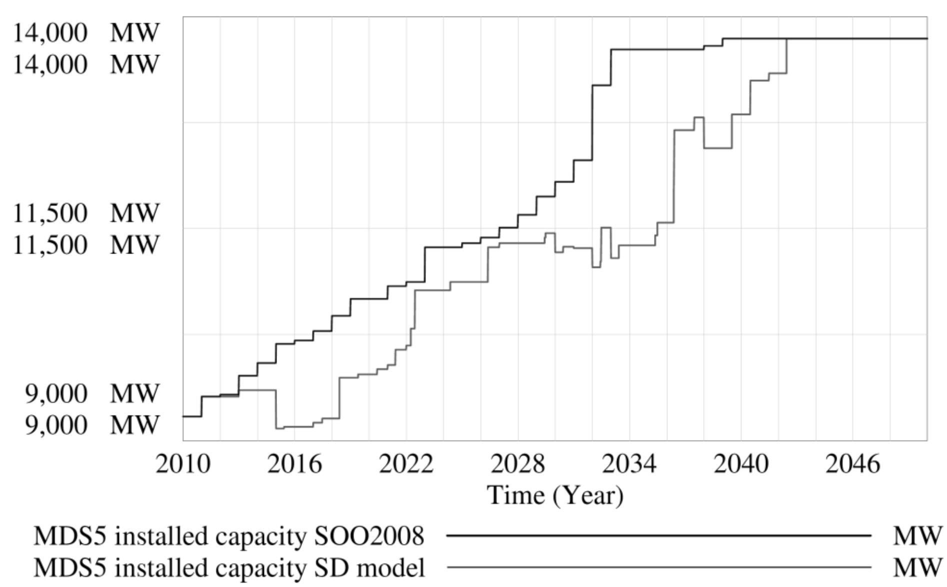


Figure 9.14: Predicted total installed capacity under MDS5 in the case of long delay

9.1.2 Impacts of delays on ECM

In this section, the impacts of delays on the ECM are discussed. The ECM resulting from various development durations under the five different scenarios are shown in Appendix E1.2. The results correspond to the statistics that are summarised in Table 9.3 . From the table, it can generally be observed that the longer the delay, the lower the minimum values of ECM become, indicating a more severe shortage. It generally does not affect the maximum ECM values since all the scheduled plants are more likely to get installed when there are high prices due to the shortages. In the case of delays, the mean ECMs are generally lower.

Figure 9.15 to Figure 9.17 show the simulation results for MDS4 under the different cases of delays. Comparing the three figures, it can be observed that delays reduce the ECM and hence increase the probability and risk of longer and more severe shortages, as indicated in Table 9.3.

.

Table 9.3: Summary table on the ECM statistics under various delays

Scenario	Delays	ECM statistics (%)			Shortage occurs?
		Min	Max	Mean	
Sustainable Path (MDS1)	Baseline	1.53	52.01	19.56	Possibly in 2019-2022, 2024-2026, 2028, 2032 and 2039-2041
	Medium delays	-4.02	52.01	18.10	Yes in 2021, 2024 and 2025. Possibly in 2015-2030, 2036, 2040-2042, after 2048.
	Long delays	-4.84	52.01	15.86	Yes in 2017, 2019-2022, 2024-2027. Possibly 2015-2035, 2039-2042, after 2048
South Island Surplus (MDS2)	Baseline	-0.29	48.74	20.28	Possibly in 2028, 2031, 2038 and 2039. Yes in 2050 if no new plants are scheduled after 2040
	Medium delays	-1.67	48.74	17.98	Yes in 2013 and 2049. Possibly in 2012-2014, 2020, 2028, 2030-2035, 2038-2042, after 2045
	Long delays	-3.24	48.74	17.16	Yes in 2014 and 2033. Possibly in winters of 2012- 2015, 2018-2021, 2028-2036, 2038, and after 2041
Medium Renewables (MDS3)	Baseline	-4.59	49.76	22.17	Possibly in winter 2031- 2033 and after 2041. Yes after 2046 if no new plants are scheduled after 2040
	Medium delays	-5.17	49.76	19.76	Yes in winter 2033-2035. Possibly in winter 2012-2013, winters of 2030 onwards (except 2037)
	Long delays	-5.83	49.76	18.04	Yes in winter 2033-2036, winter 2039-2042, after 2046. Possibly in winter 2012-2014, after 2030
Demand-side Participa-tion (MDS4)	Baseline	-0.33	54.12	24.53	Possibly from winter of 2028 until 2030. Yes in 2031
	Medium delays	-5.03	54.12	21.85	Yes in winter of 2013 and winters of 2027-2033
	Long delays	-6.42	54.12	20.61	Yes in winters of 2013-2014 and 2027-2033
High Gas Recovery (MDS5)	Baseline	1.60	46.99	20.31	Possibly in 2016, 2017, 2030, 2038-2040
	Medium delays	-4.22	46.99	18.75	Yes in winters of 2015-2017 and 2034-2035. Possibly in 2015-2025, 2030-2035, 2038-2040, 2047 onwards
	Long delays	-4.22	46.99	16.94	Yes in winters od 2015-2017 and 2033-2035. Possibly in 2015-2025, 2028-2035, 2038-2040, 2047 onwards

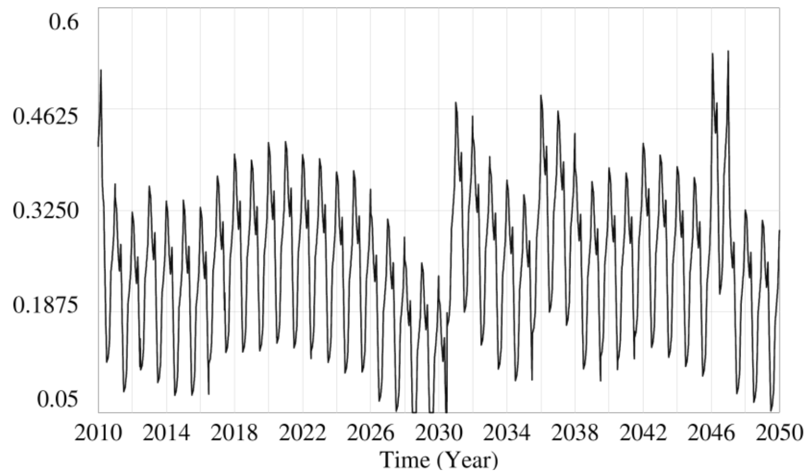


Figure 9.15: ECM for baseline case under MDS4

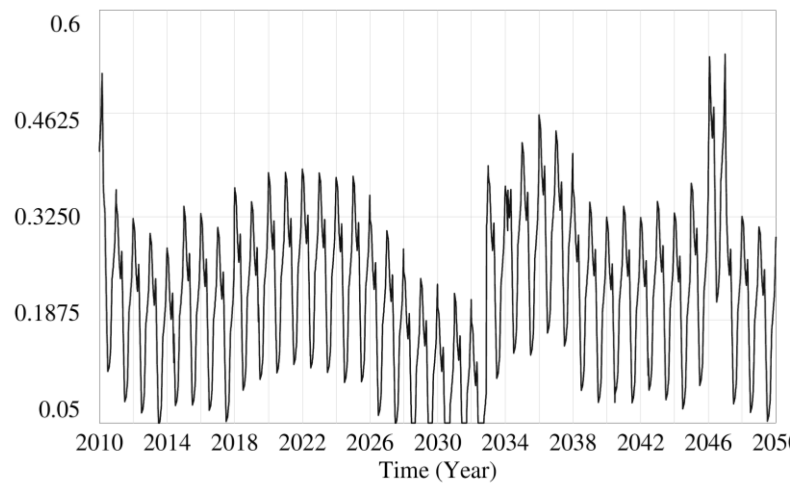


Figure 9.16: ECM for the case of medium delays under MDS4

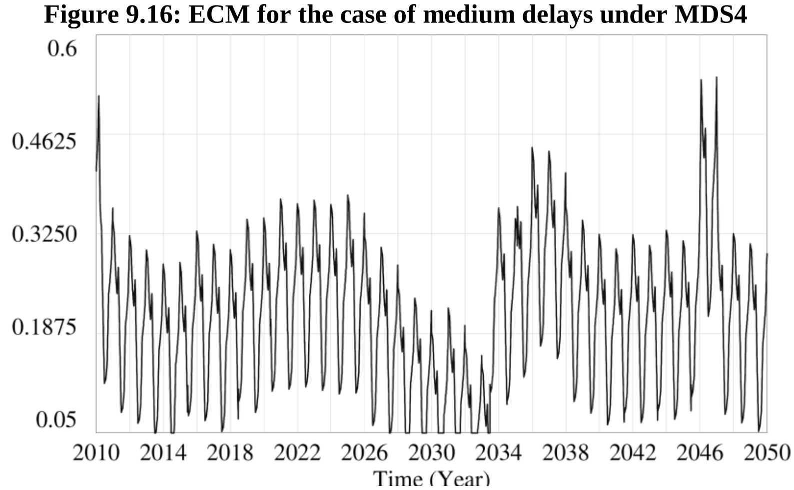


Figure 9.17: ECM for the case of long delays under MDS4

9.1.3 Impacts on CM

Appendix E1 contains the figures showing the simulation results of the CM under the various cases of delay for all the five scenarios. The statistics of the results are summarised in Table 9.4.

Table 9.4: Summary table on the CM statistics under various delays

Scenario	Delays	CM statistics (%)			Security risk occurs?
		Min	Max	Mean	
Sustainable Path (MDS1)	Baseline	16.28	38.36	28.39	No
	Medium delays	13.75	44.22	30.86	Possibly in 2019
	Long delays	9.26	40.19	28.10	Possibly in 2018, 2019-2022, 2024
South Island Surplus (MDS2)	Baseline	17.64	33.54	26.18	No
	Medium delays	14.45	35.95	25.00	Possibly in 2014
	Long delays	12.79	34.29	24.78	Possibly in 2014-2015
Medium Renewables (MDS3)	Baseline	4.49	25.32	18.87	Possibly from 2030-2033 and 2045 if no new plants are scheduled after 2040
	Medium delays	2.62	24.73	16.58	Possibly from 2029-2036, 2038-2040 and 2045 onwards if no new plants are scheduled after 2040
	Long delays	15.0	25.56	15.18	Possibly from 2029-2037, 2039 and 2045 onwards if no new plants are scheduled after 2040
Demand-side Participation (MDS4)	Baseline	9.85	28.93	22.44	Possibly between 2028 and 2031
	Medium delays	8.13	27.90	20.47	Possibly between 2027 and 2033
	Long delays	5.33	27.53	19.40	Possibly between 2027 and 2033
High Gas Recovery (MDS5)	Baseline	12.83	25.50	20.04	Possibly in 2015, 2038 and 2040
	Medium delays	10.31	25.02	17.93	Possibly in 2015-2017, 2019, 2031-2033, 2036-2039 and 2047 onwards
	Long delays	9.06	25.02	16.71	Possibly in 2015-2018, 2019-2022, 2030-2036, 2039 and 2047 onwards

From the table, it can generally be observed that the longer the delay, the lower the minimum values of CM become, indicating a higher risk of system security. The mean CMs are also generally lower. There is no obvious effect of the impact of the delays on the maximum ECM values.

9.1.4 Discussions on delay impacts onto CM

Figure 9.18 to Figure 9.20 are taken from the results of MDS4 for the different cases of delays. Comparing the three figures, it can be observed that delays bring down the CM, increasing the probability of longer and more severe system security problems, as indicated in Table 9.6.

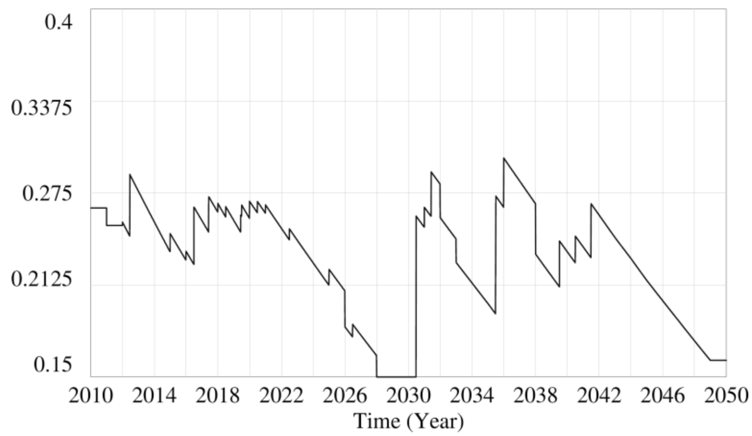


Figure 9.18: CM for baseline case under MDS4

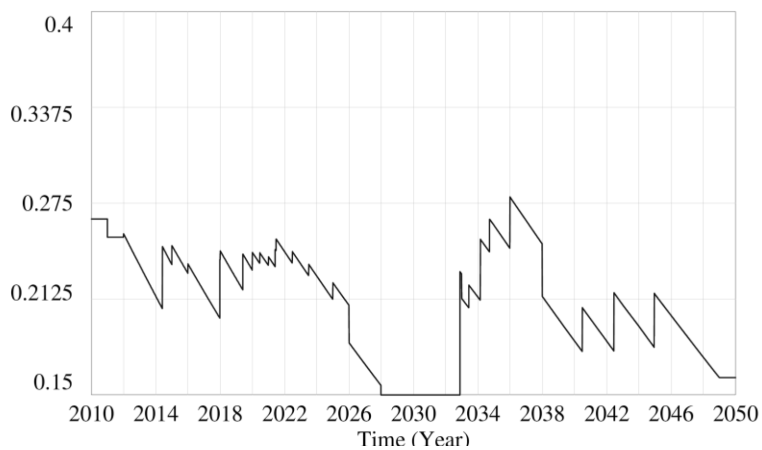


Figure 9.19: CM for the case of medium delay under MDS4

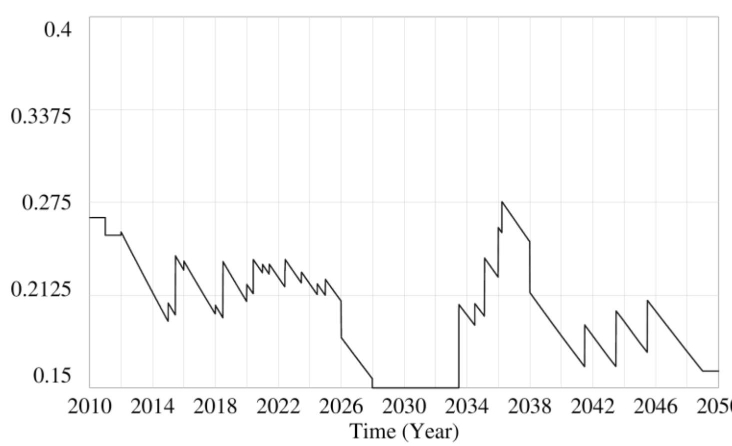


Figure 9.20: CM for the case of long delay under MDS4

9.2 Impacts of variations in the load forecasts

As mentioned in the chapter's introduction, there is a 10% probability of the load growth being higher than the forecasted load growth. Figure 9.21shows the baseline load growth, whereas Figure 9.22 shows the high load growth, for all the MDS.

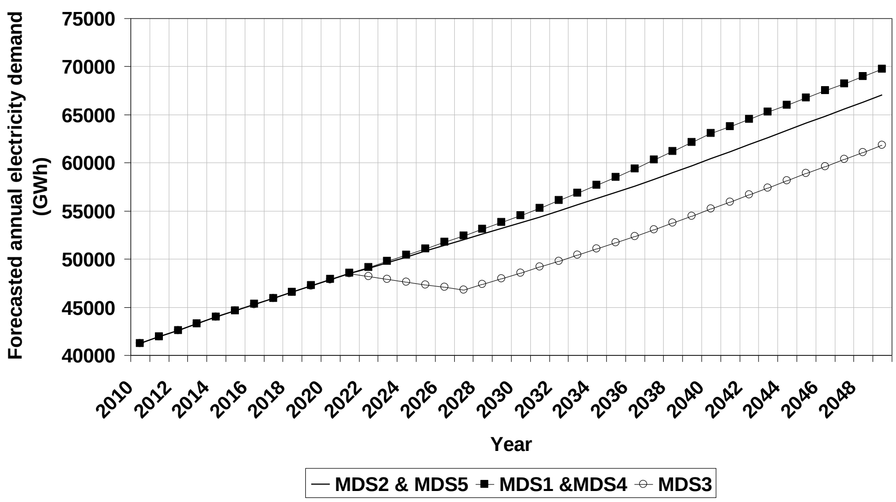


Figure 9.21: Baseline growth load forecast

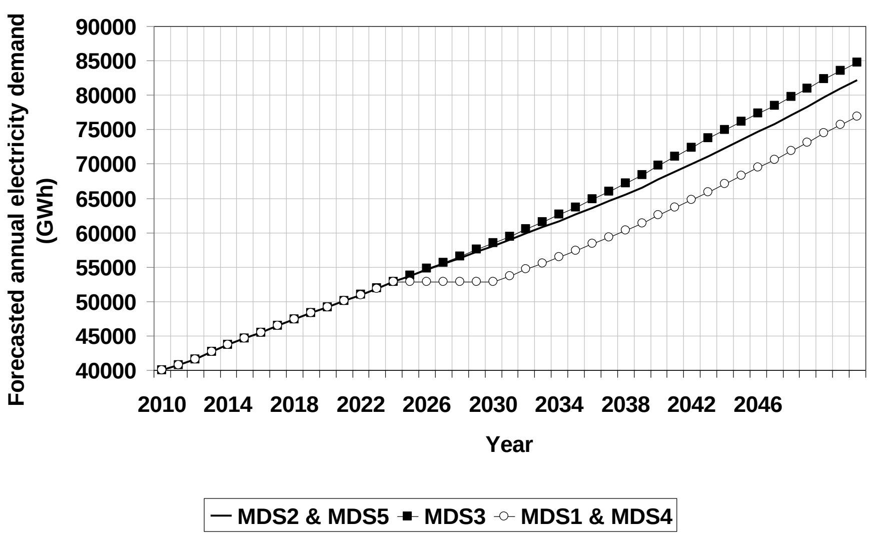


Figure 9.22: High growth load forecast

The simulation results using the baseline and high load growths are shown in Appendix E2. The following sections discuss the impacts of the variations in the load forecasts on the different model outputs.

9.2.1 Impacts on installed generation capacities

The resultant installed capacities for the baseline and high load growths indicate that higher load consumption stimulates and speeds up power plant development. The result for MDS1 (Figure 9.23) shows that the installed capacities under the high load growth increase faster compared to the capacities under the baseline growth, indicating that power plants get developed and commissioned quicker. The high load also allows more scheduled plants to get commissioned, resulting in higher total installed capacities by 2050.

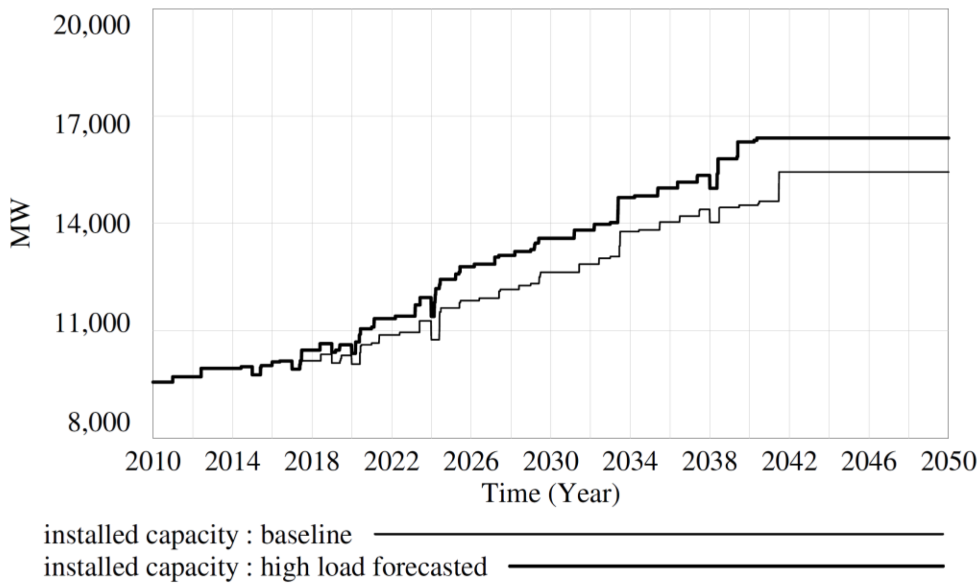


Figure 9.23: Installed capacities for different load growth projections under MDS1

9.2.2 Impacts on ECM

The figures of ECMs under the different load projections suggest that ECMs are lower under high load growth. Even though more power plants get commissioned, the development is not fast enough to keep up with the load growth. Figure 9.24 shows the ECMs under MDS1. It can be observed that the ECMs for high load are significantly lower. The statistics for the results under all MDS are shown in

Table 9.5. Under all the MDS, the mean and minimum values of the ECMs for high load growth are lower than for the baseline growth. Due to the lower ECMs, more supply shortages are forecasted.

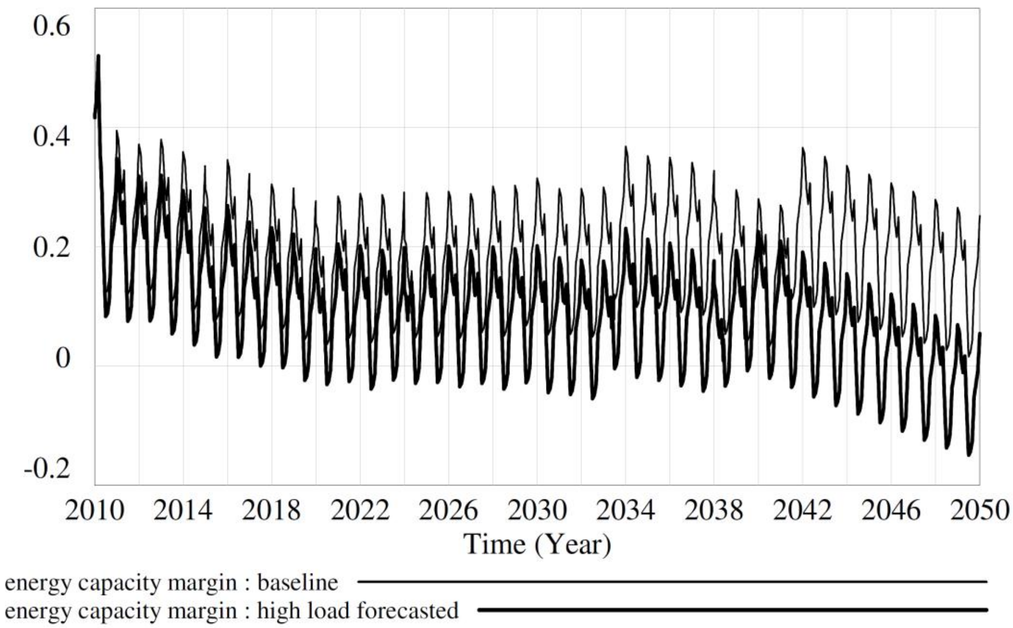


Figure 9.24: ECM for different load growth projections under MDS1

Table 9.5: Summary table on the ECM statistics under different demand growth

Scenario	Delays	ECM statistics (%)			Shortage occurs?
		Min	Max	Mean	
Sustainable Path (MDS1)	Baseline	1.53	52.01	19.56	None
	High demand growth	-15.01	52.01	9.11	Yes in every winters of 2019 onwards
South Island Surplus (MDS2)	Baseline	-0.29	48.74	20.28	Yes in 2050 if no new plants are scheduled after 2040
	High demand growth	-18.76	48.73	20.31	Yes, in winters of 2028 onwards
Medium Renew-ables (MDS3)	Baseline	-4.59	49.75	22.17	Yes after 2046 if no new plants are scheduled after 2040
	High demand growth	-23.28	49.75	9.21	Yes in winter 2028 onwards
Demand-side Participa-tion (MDS4)	Baseline	-0.33	54.12	24.53	Yes in 2031
	High demand growth	-10.42	51.55	14.58	Yes in winter 2030,2032,2038 and 2043 onwards
High Gas Recovery (MDS5)	Baseline	1.60	46.99	20.31	None
	High demand growth	-17.21	46.98	8.11	Yes, in all winters of 2015-2050

9.2.3 Impacts on CM

The forecasted peak loads with baseline and high load growth for the various MDS are shown in Figure 9.25 (for all MDS except MDS3) and Figure 9.26 (for MDS3). Peak load growths under MDS3 are slower after 2020 because of the assumption that the Tiwai aluminium smelter will be decommissioned in that year.

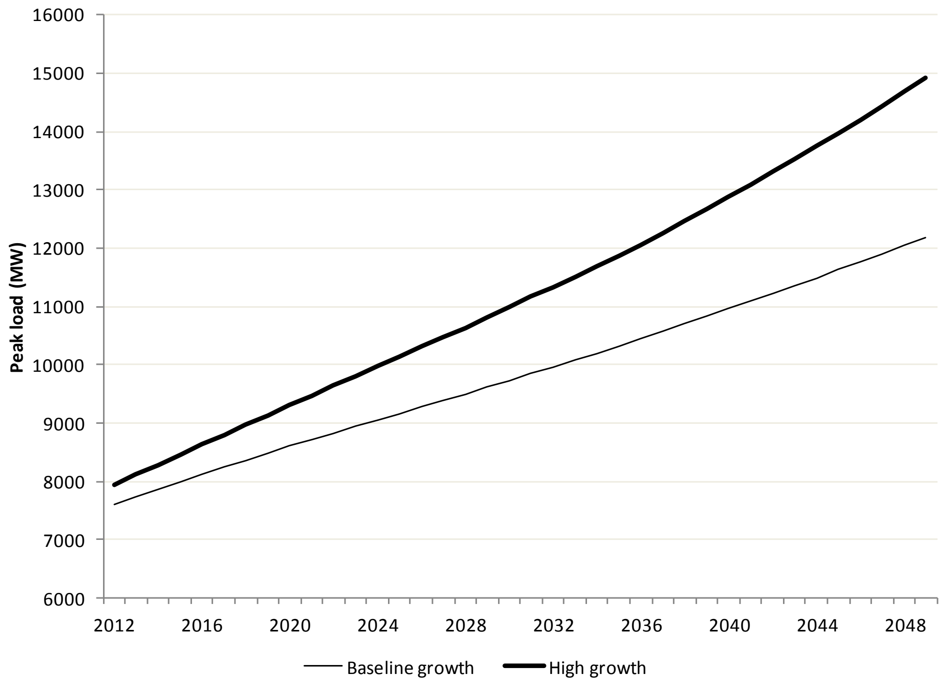


Figure 9.25: Forecasted peak load growth for all MDS except MDS3 (Electricity Commission 2008)

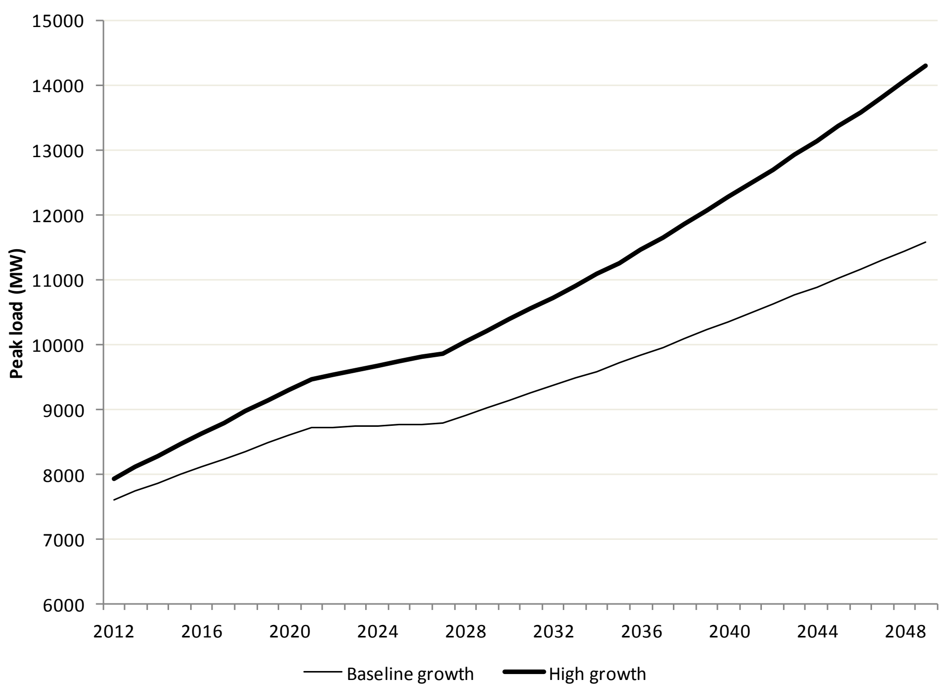


Figure 9.26: Forecasted peak load growth for MDS3 (Electricity Commission 2008)

Figure 9.27 shows the CMs for baseline and high growth in the peak load projection under MDS2. From the figure, it can be observed that the CMs for high growth are lower than the baseline case. The statistics for results under other MDS are shown in Table 9.6. The table shows that the CMs for high load growth are lower in their mean, maximum and minimum values. Security risks are predicted under MDS2, MDS4 and MDS5 if there are no other plants scheduled after 2040. This indicates that even though there are more total installed generation capacities resulting from the high load growth, the capacities do not increase fast enough to keep up with the demand.

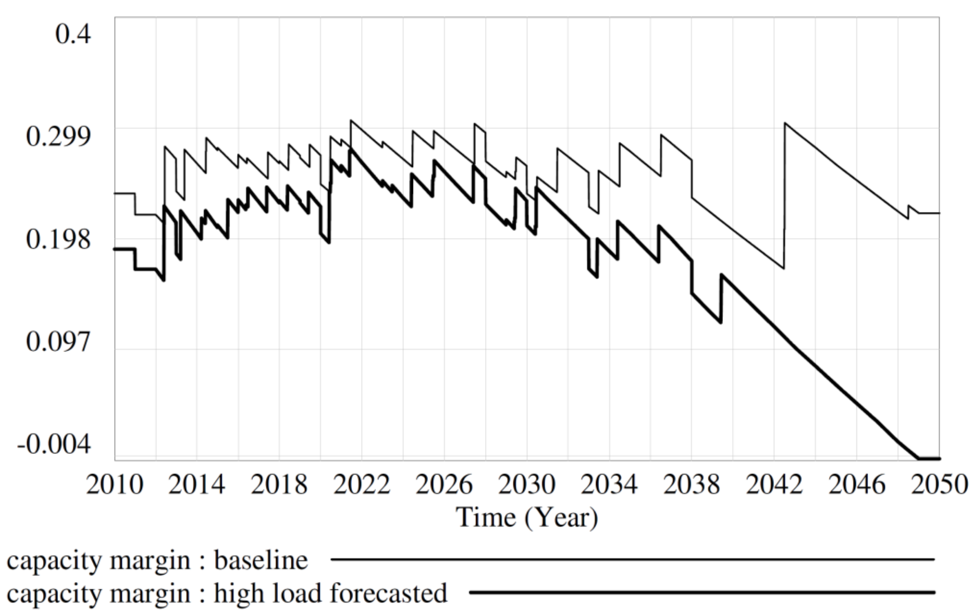


Figure 9.27: CM for different load growth projections under MDS2

Table 9.6: Summary of the CM statistics for various load growth

Scenario	Load growth	CM statistics (%)			Security risk occurs?
		Min	Max	Mean	
Sustainable Path (MDS1)	Baseline	16.28	38.36	28.39	No
	High demand growth	9.85	27.49	20.12	No
South Island Surplus (MDS2)	Baseline	17.64	33.54	26.18	No
	High demand growth	-0.28	27.96	17.80	Yes after 2049 if no new plants are scheduled after 2040
Medium Renew-ables (MDS3)	Baseline	4.49	25.32	18.87	Possibly from 2030-2033 and 2045 if no new plants are scheduled after 2040
	High demand growth	10.57	29.53	22.34	No
Demand-side Participa-tion (MDS4)	Baseline	9.85	28.93	22.44	Possibly between 2028 and 2031
	High demand growth	-2.49	23.27	12.5	Yes after 2047 if no new plants are scheduled after 2040
High Gas Recovery (MDS5)	Baseline	12.83	25.50	20.04	Possibly in 2015, 2038 and 2040
	High demand growth	-7.86	19.9	8.27	Yes after 2044 if no new plants are scheduled after 2040

9.3 Impacts of weather factor / dry year

As discussed in Chapter 5, hydro is the dominant electricity resource in New Zealand. History has shown that weather can have a major impact on energy security during dry winters. The capacity stackplots in Appendix C3 show that hydro is predicted to still be the dominant resource under all five scenarios. Hence, it is useful to study the impacts of dry years on the energy and system security. Part of the results in this analysis have been presented at an IEEE international conference proceedings in Trondheim, Norway (Jalal and Bodger 2011).

The hydro inflows in New Zealand are highly dependent on the season. The natural lake cycles cause high lake levels heading into summer (around December), reducing levels during summer and autumn, and increasing levels during winter (around June) and spring (Opus International Consultants Limited 2009). Figure 9.28 demonstrates the seasonal variation of lake level for Lake Wanaka from 1998 to 2008. It is part of the catchment for the Clutha River hydro scheme (750MW) located in the South Island, New Zealand.

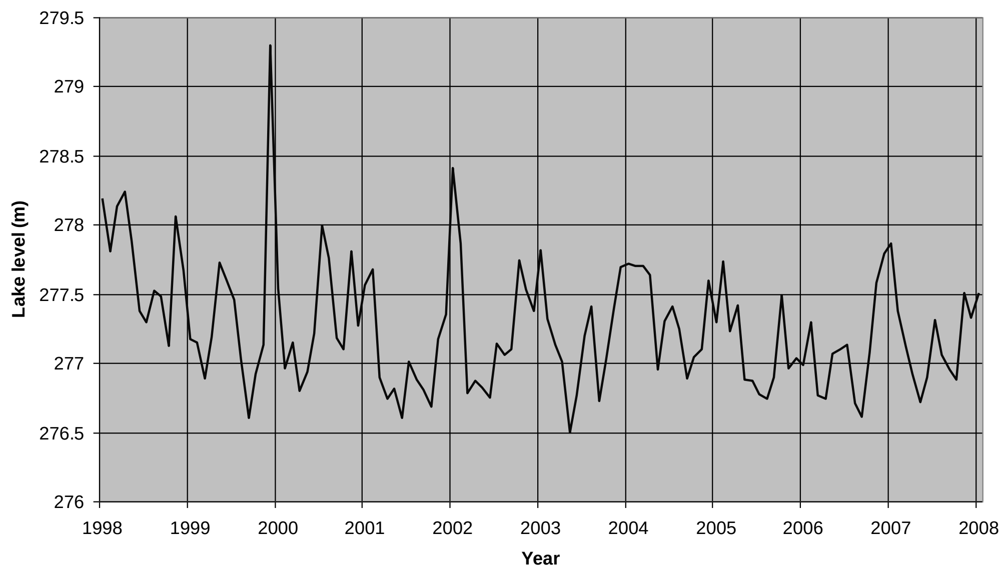


Figure 9.28: Lake Wanaka levels from 1998 and 2008 (Opus International Consultants Limited 2009)

Depending on the location, the inflows into storage lakes can also be affected by the El Niño-La Niña Southern Oscillation (ENSO). Monitoring of inflows to New Zealand's hydroelectric lakes stretches back to the 1920s. With the benefit of such a long time series, New Zealand's National Institute of Water and Atmospheric Research (NIWA) can show that the flow into South Island hydro lakes in La Niña years is considerably lower than the flow for other years (National Institute of Water and Atmostpheric Research 2008).The schemes in the South Island account for 66% of the total installed hydro capacity in New Zealand (Electricity Commission 2010). This is almost twice the capacity of hydro schemes in the North Island. Hence, drought in the South Island lake catchments causes a serious problem for hydro resources in New Zealand.

From Figure 9.29, it can be observed that severe La Niña happens at least once in every seven years (National Institute of Water and Atmostpheric Research 2008). The y-axis represents the Southern Oscillation Index (SOI) which indicates the severity of the ENSO. For La Niña, the higher the SOI, the worse is its severity. The figure also shows that energy shortages in New Zealand in 2001, 2003 and 2008 coincided with severe La Niña occurrences.

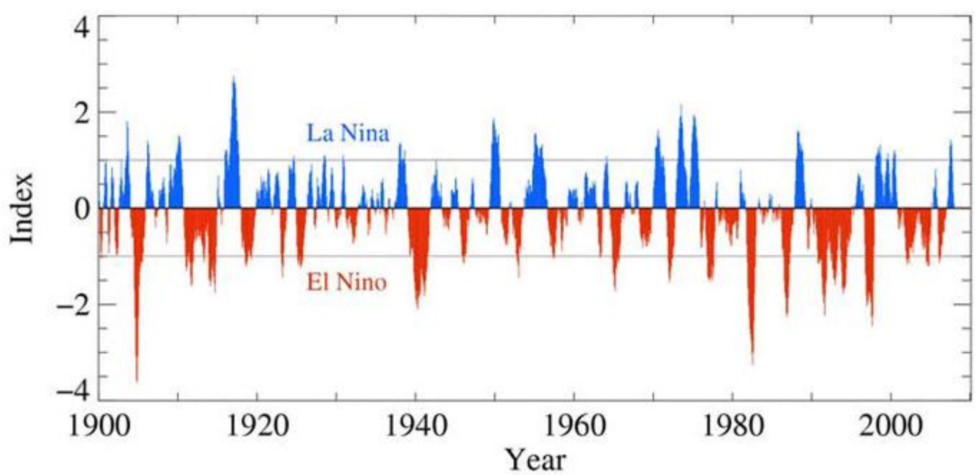


Figure 9.29: Global ENSO occurrence in the last 110 years (National Institute of Water and Atmostpheric Research 2008)

The GEM model used a constant plant availability factor for hydro plants. In the previous analyses, the SD model also used a constant plant availability to allow for fair comparisons between the two models. In this analysis, the SD model uses variable hydro plant availability factors (AF) for the different months of the year to take into account the lake level cycles (see Figure 9.30). The monthly average values are calculated from past hydrological data of the main hydro lakes in New Zealand. The calculations are discussed in the next section. To include the impact of a severe La

Niña on the hydro resources, the SD model includes its effects once every seven years with dry winters occurring in 2015, 2022, 2029, 2036 and 2043. This model is deemed adequate since it is not the research objective to perform accurate forecasting of hydro data.

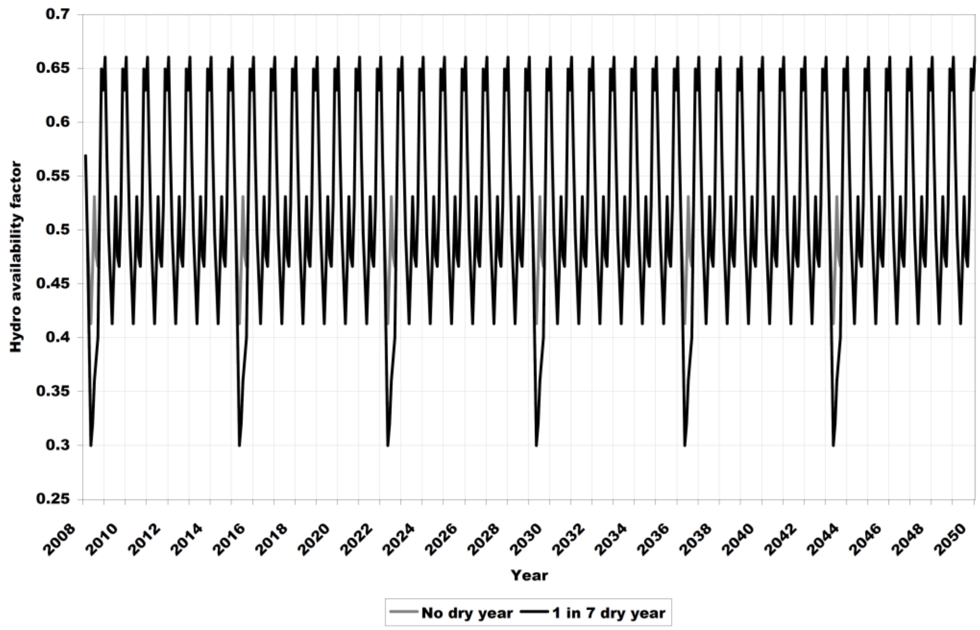


Figure 9.30: Hydro AF used by the SD model in the dry year analysis

9.3.1 Dry year model development

The steps for the average hydro availability data calculations are:

1. The lake level history data for the main storage lakes in New Zealand from July 1996 to June 2008 are used in formulating the dry dear model. The lakes

considered are Taupo[1], Tekapo[2], Pukaki[2], Manapouri[3], Wanaka and Hawea[4]. These lakes are chosen because of they are the main storage for the larger power plants in New Zealand.

2. Their monthly availability factor are calculated in Equation 1:

Monthly availability factor

$$= \frac{\text{Monthly average lake level - minimum operating level}}{\text{Maximum operating level - minimum operating level}}$$

Equation 1

3. However, the SD model looks at the hydro availability at a national level. Hence, depending on the contribution of the lakes to the national electricity demand, weighted averages are calculated to obtain the national monthly AF. Different weights are used within different durations to take into account system upgrades of the various hydro plants utilising the lakes involved (see Table 9.7).

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[1] Lake Taupo is the main storage for the Waikato hydro scheme.

[2] Lakes Tekapo and Pukaki are the main storage for the Waitaki hydro scheme.

[3] Lake Manapouri feeds the largest hydro power station in New Zealand, Manapouri plant.

[4] Lakes Wanaka and Hawea are the main storage for Clutha hydro scheme.

Table 9.7: The weights applied to the monthly hydro availability averages for the different lakes

Lake/ Year	1977-1984		1984-1985		1985-1992		1992-2002		2002-2009	
	Installed capacity	Weight (%)	Installed capacity	Weight (%)	Installed capacity	Weight (%)	Installed capacity	Weight (%)	Installed capacity	Weight (%)
Taupo	1072	0.31	1072	0.29	1072	0.28	1072	0.25	1072	0.24
Tekapo (Waitaki River Scheme)	185	0.05	185	0.05	185	0.05	185	0.04	185	0.04
Pukaki (Waitaki River Scheme)	1129	0.33	1341	0.37	1553	0.40	1553	0.36	1553	0.35
Manapouri	730	0.21	730	0.20	730	0.19	730	0.17	850	0.19
Wanaka & Hawea (Clutha River Scheme)	320	0.09	320	0.09	320	0.08	752	0.18	752	0.17
Total	**3436**	**1**	**3648**	**1**	**3860**	**1**	**4292**	**1**	**4412**	**1**

Applying the weights shown in Table 9.7 to the monthly availability factors calculated in Step 1 yielded the results presented in Table 9.8. The low values observed, especially for the year dry years in 2001, 2003 and 2008, were used to decide the appropriate values to apply in modelling a dry year.

Table 9.8: Historical monthly average hydro AF calculated for July 1996 to June 2008

Year/Month	Jan	Feb	Mac	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1996							0.40	0.40	0.57	0.96	0.59	0.61
1997	0.44	0.54	0.41	0.61	0.41	0.38	0.37	0.57	0.38	0.54	0.75	0.85
1998	0.63	0.84	0.78	0.65	0.47	0.55	0.79	0.59	0.61	1.00	0.55	0.53
1999	0.48	0.38	0.51	0.50	0.63	0.52	0.46	0.39	0.42	0.55	1.00	0.49
2000	0.54	0.47	0.31	0.51	0.55	0.79	0.56	0.46	0.61	0.83	0.46	0.80
2001	0.51	0.44	0.39	0.32	0.38	0.50	0.31	0.41	0.35	0.48	0.62	0.97
2002	0.75	0.39	0.42	0.35	0.38	0.68	0.50	0.54	0.76	0.53	0.58	0.76
2003	0.48	0.46	0.34	0.25	0.54	0.59	0.46	0.33	0.59	0.60	0.66	0.67
2004	0.68	0.76	0.62	0.34	0.57	0.69	0.48	0.51	0.51	0.55	0.63	0.57
2005	0.66	0.53	0.55	0.30	0.43	0.38	0.41	0.41	0.50	0.48	0.41	0.49
2006	0.65	0.39	0.34	0.54	0.47	0.48	0.45	0.47	0.54	0.57	0.87	0.63
2007	0.55	0.38	0.40	0.28	0.44	0.42	0.51	0.52	0.42	0.71	0.45	0.57
2008	0.45	0.39	0.40	0.31	0.32	0.38						
Average	**0.57**	**0.50**	**0.46**	**0.41**	**0.46**	**0.53**	**0.48**	**0.47**	**0.52**	**0.65**	**0.63**	**0.66**

Severely low	AF<0.3
Low	0.3<AF<0.35
Medium low	0.35<AF<0.4

The monthly averages (in **bold**) are used for normal years whereas the AF values for a dry year are shown in Table 9.9. Different AF values in any month between the two years are *italicized*. The dry year AF values are only applicable in the months where the lake inflows are usually low in the year. It is assumed that lake inflows start to increase again during winter as part of the usual lake cycles in New Zealand.

Table 9.9: Monthly AF applied in the SD model for a normal year and a dry year

Month	No dry year	1 in 7 dry year
January	0.57	0.57
February	0.50	0.50
March	0.46	*0.40*
April	0.41	*0.30*
May	0.46	*0.32*
June	0.53	*0.36*
July	0.48	*0.38*
August	0.47	*0.40*
September	0.52	0.52
October	0.65	0.65
November	0.63	0.63
December	0.66	0.66

9.3.2 Dry year model validation

Similar to the model validation work discussed in Chapter 7, the dry year model has been validated using past data. The plot of the AF values in Table 9.9 is shown in Figure 9.31. The AF values are compared with the historical hydro AF.

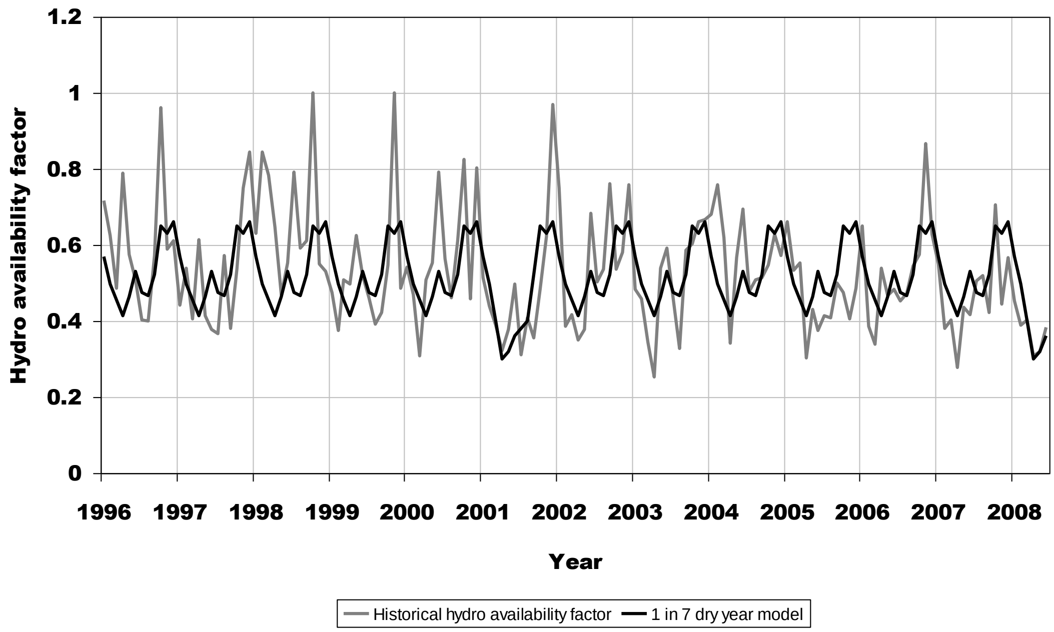

Figure 9.31: Comparison of hydro AFs used in the model validation with actual historical data

Even though the modelled AF did not represent the AF for the dry year in 2003, the resultant installed capacity is close to the historical installed capacity. The results are also close to the SD model results when the model was simulated using the historical hydro data. These results are shown in Figure 9.32. Since the dry year model's result is close to the historical data, the model is suitable to be used for future forecasting. The hydro input data for the forecasting is previously shown in Figure 9.30.

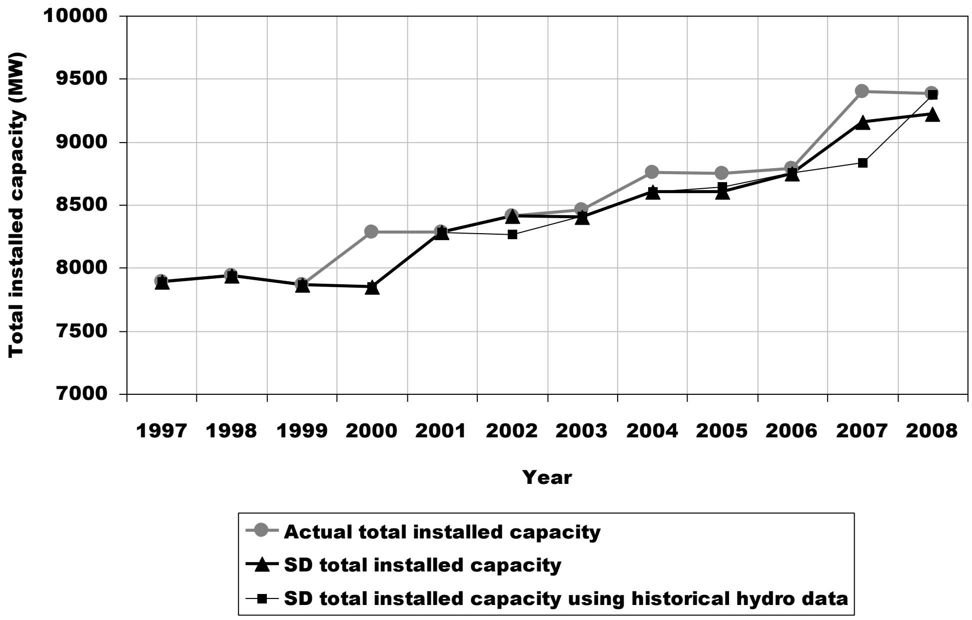

Figure 9.32: Comparison between the historical installed capacity and the SD model total installed capacity taken annually in December

9.3.3 Impacts on installed generation capacities

Applying the dry year model for the simulated years of 2010 to 2050 under the five different scenarios gave the results shown in Figure 9.33 to Figure 9.37.

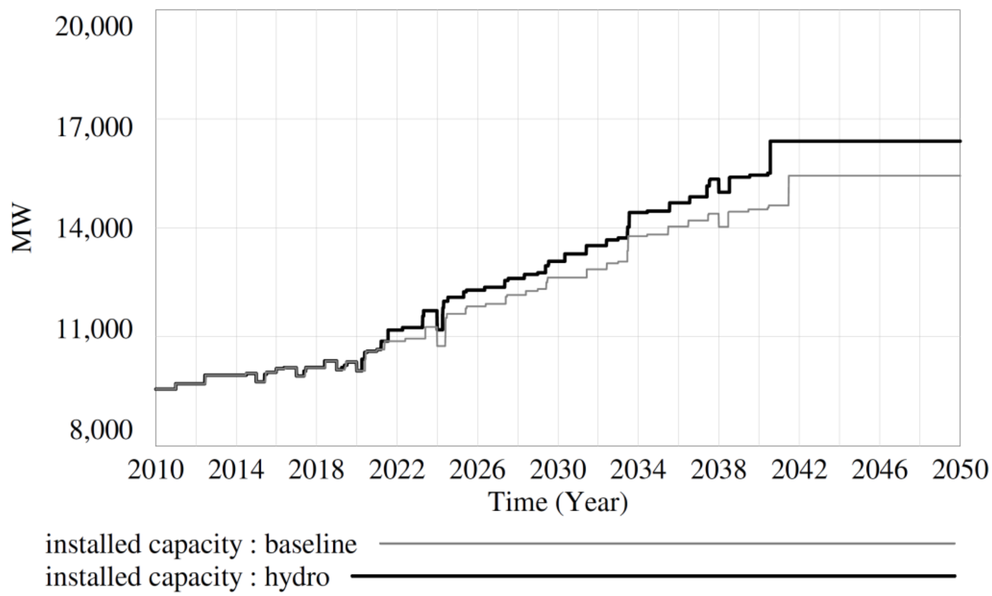

Figure 9.33: Comparison of the results between the baseline and dry years cases for MDS1

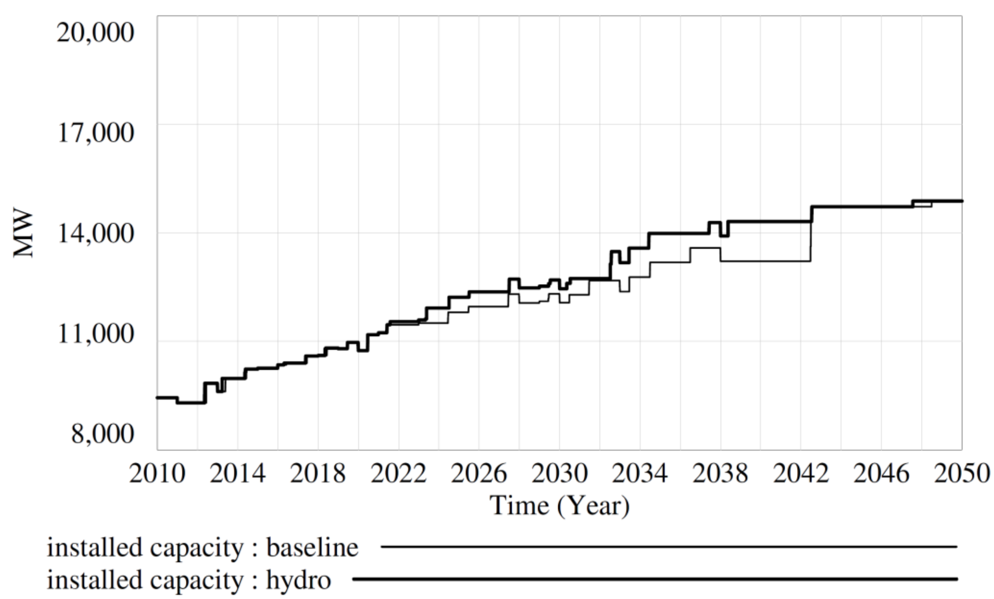

Figure 9.34: Comparison of the results between the baseline and dry years cases for MDS2

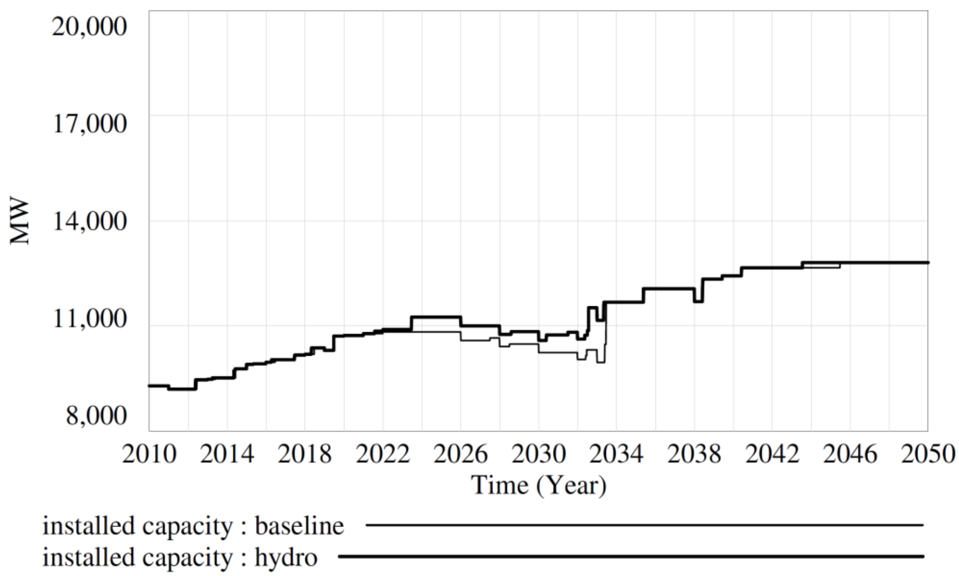

Figure 9.35: Comparison of the results between the baseline and dry years cases for MDS3

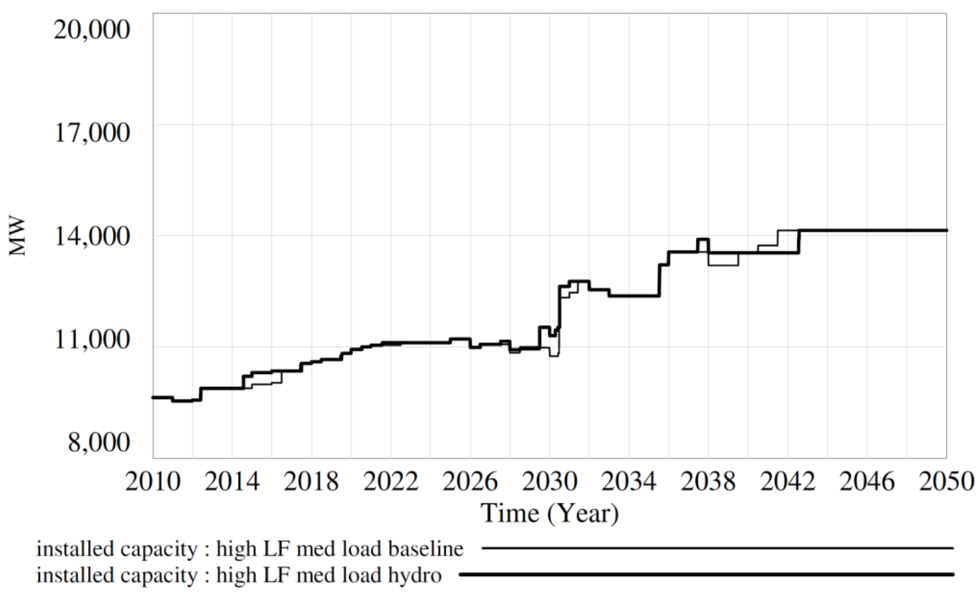

Figure 9.36: Comparison of the results between the baseline and dry years cases for MDS4

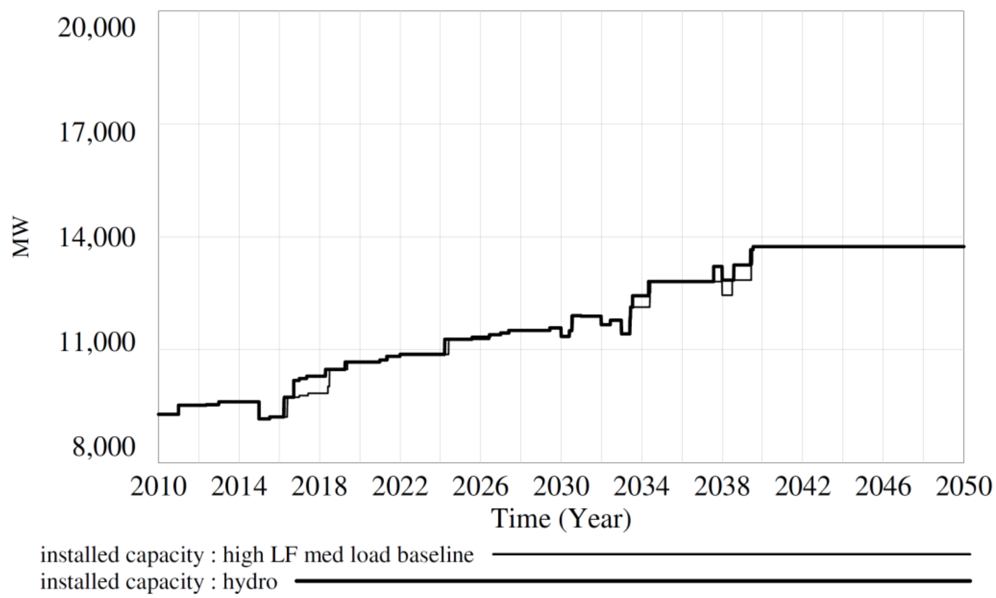

Figure 9.37: Comparison of the results between the baseline and dry years cases for MDS5

From the figures, it can be observed that the results between the baseline and hydro shortage cases vary more when there is a bigger percentage of hydro in the generation mix such as in MDS1 and MDS2. The occurrences of dry years also cause the installed capacities to be commissioned faster since they are usually accompanied by high prices. The system susceptibility to shortages (measured by the ECMs) during dry years are discussed in the next section.

9.3.4 Impacts on ECM

The ECMs for the dry year analysis under all five scenarios are shown in Figure 9.38 to Figure 9.42. They are compared to the ECM values for the baseline case. It can be observed that the ECMs for the dry year analysis became negative during every modelled dry winter under most scenarios, indicating the predicted occurrences of energy shortages.

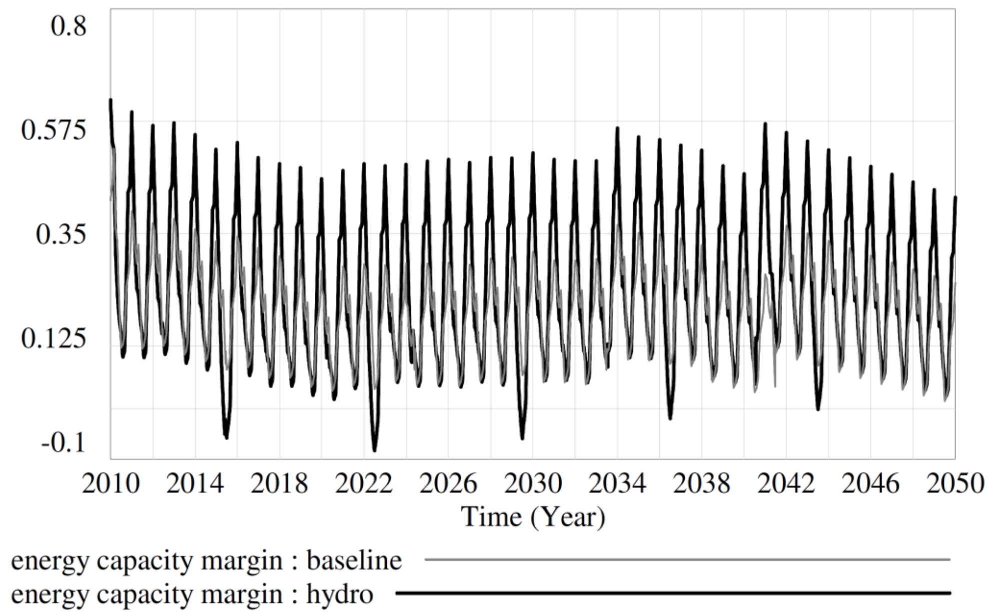

Figure 9.38: Forecasted ECM for MDS1

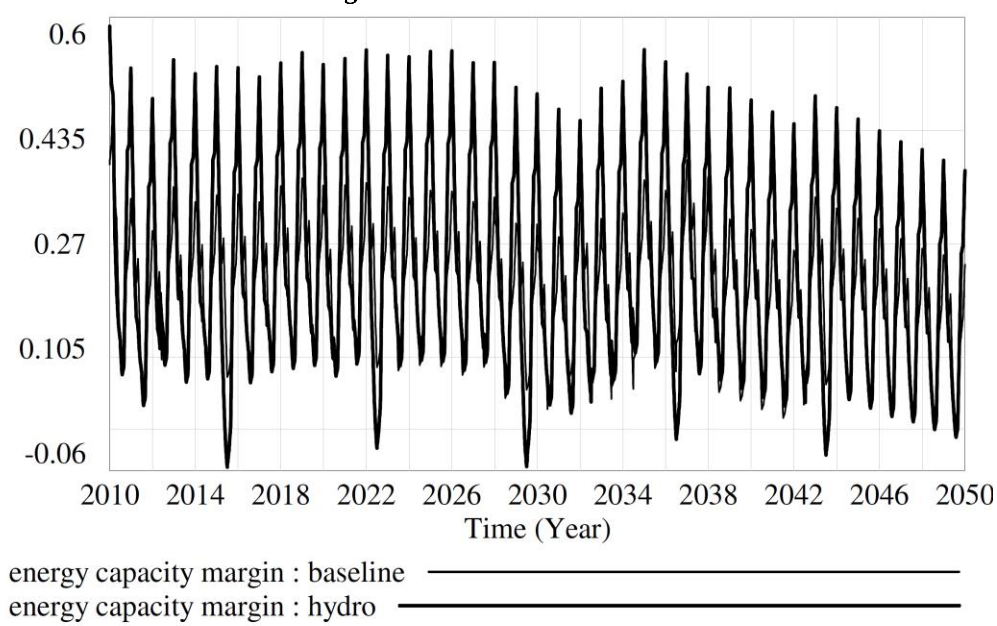

Figure 9.39: Forecasted ECM for MDS2

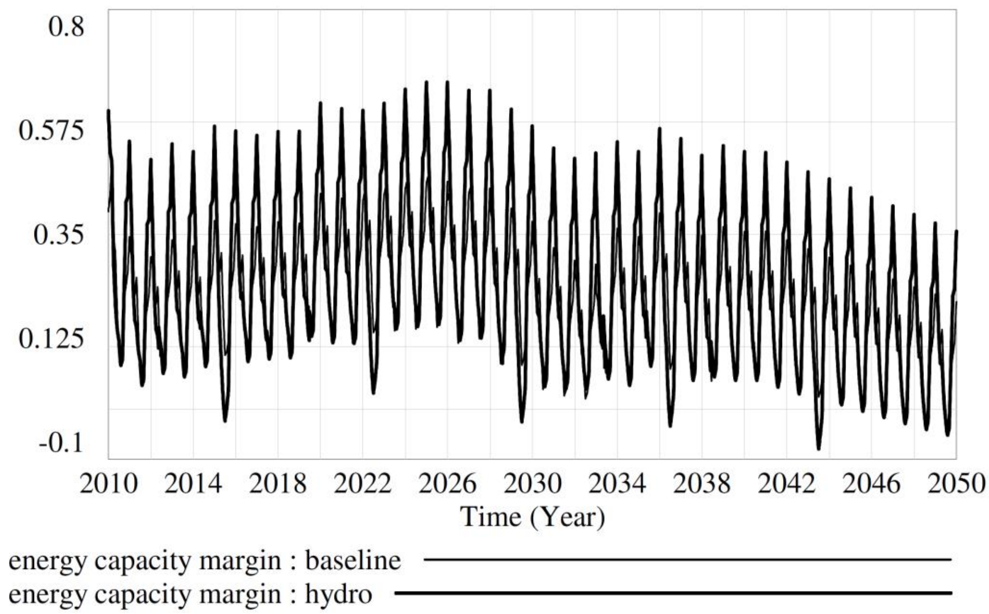

Figure 9.40: Forecasted ECM for MDS3

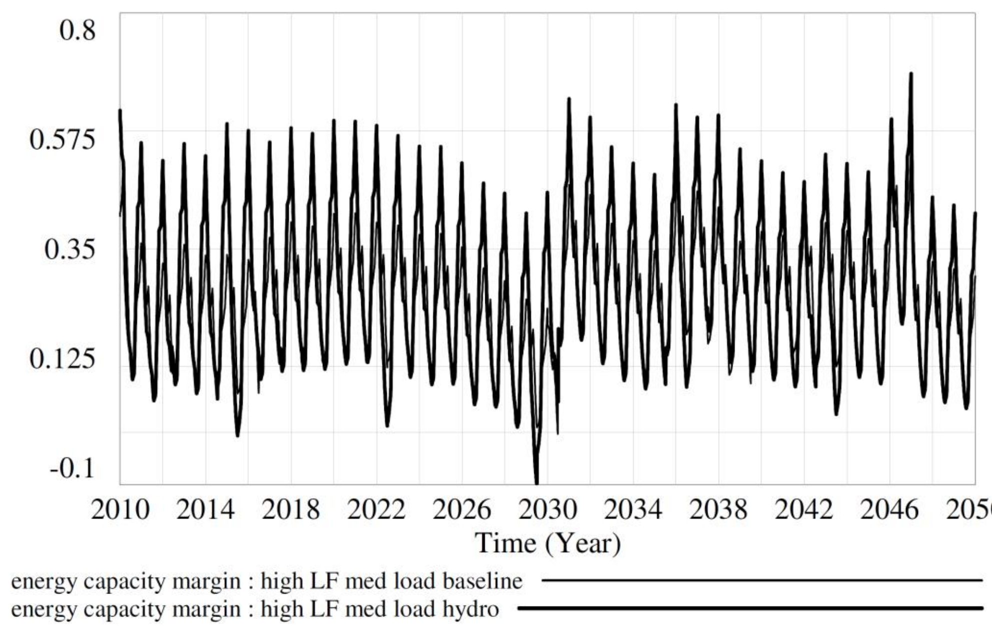

Figure 9.41: Forecasted ECM for MDS4

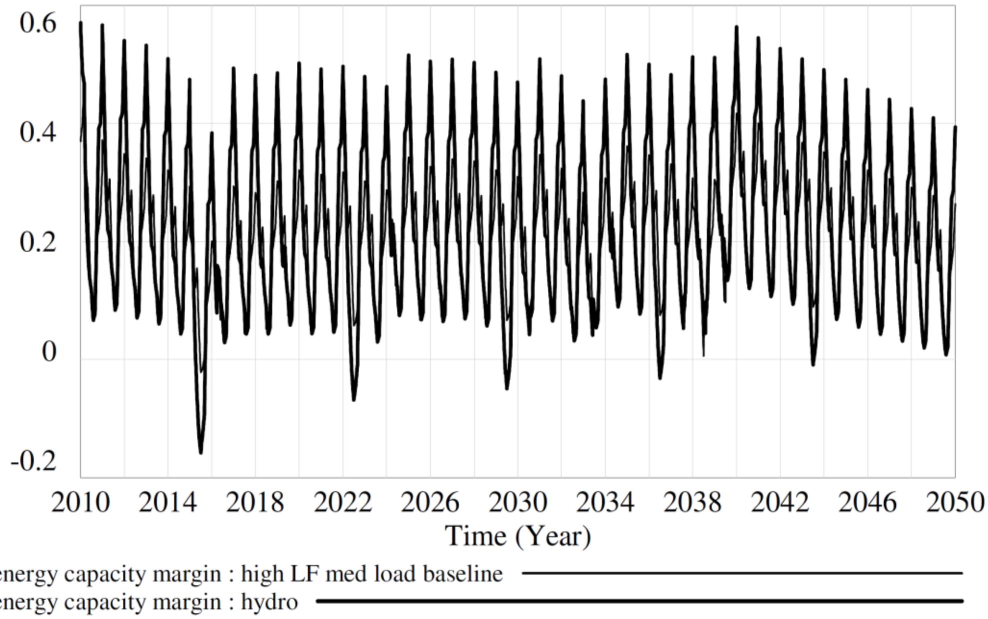

Figure 9.42: Forecasted ECM for MDS5

The resultant ECMs for all five scenarios are summarised in Table 9.10. Shortages are forecasted to happen during dry winters under all MDS. The least number of shortages are observed under MDS4. The severest shortage is predicted for the year 2015 under MDS5.

Table 9.10: Summary of ECM statistics for the dry year analysis

Scenario	Delays	ECM statistics (%)			Shortage predicted?
		Min	Max	Mean	
Sustainable Path (MDS1)	Baseline	1.53	52.01	19.56	None
	Dry years	-8.39	61.75	23.66	Yes in every modelled dry winter
South Island Surplus (MDS2)	Baseline	-0.29	48.74	20.28	Yes in 2050 if no new plants are scheduled after 2040
	Dry years	-5.57	58.69	23.25	Yes in every modelled dry winter, after 2049 if no new plants are scheduled after 2040
Medium Renewables	Baseline	-4.59	49.76	22.17	Yes after 2046 if no new plants are scheduled after

(MDS3)					2040
	Dry years	-8.03	65.43	25.09	Yes in every modelled dry winter, after 2045
Demand-side Participation (MDS4)	Baseline	-0.33	54.12	24.53	Yes in 2031
	Dry years	-9.78	68.43	27.38	Yes in 2015 and 2029
High Gas Recovery (MDS5)	Baseline	1.60	46.99	20.31	None
	Dry years	-15.84	57.06	22.71	Yes in every modelled dry winter

The SD model results from the dry year analyses indicate the impact of generation mix onto New Zealand's energy security. High hydro penetration as in MDS1 and MDS2 can cause future energy shortages during dry years.

However, under the current market structure, having more thermal plants aggravates the bust and boom patterns in the installed capacities. More severe shortages can occur if bust periods are accompanied with a dry winters. An example of this is for the year 2015 under MDS5. The bust period in that year, as shown in Table 9.10, resulted in the worst predicted shortage (ECM of -15.8%).

9.3.5 Impacts on CM

The CMs for the dry year analysis under all five scenarios are shown in Figure 9.43 to Figure 9.47. They are compared to the CM values for the baseline case.

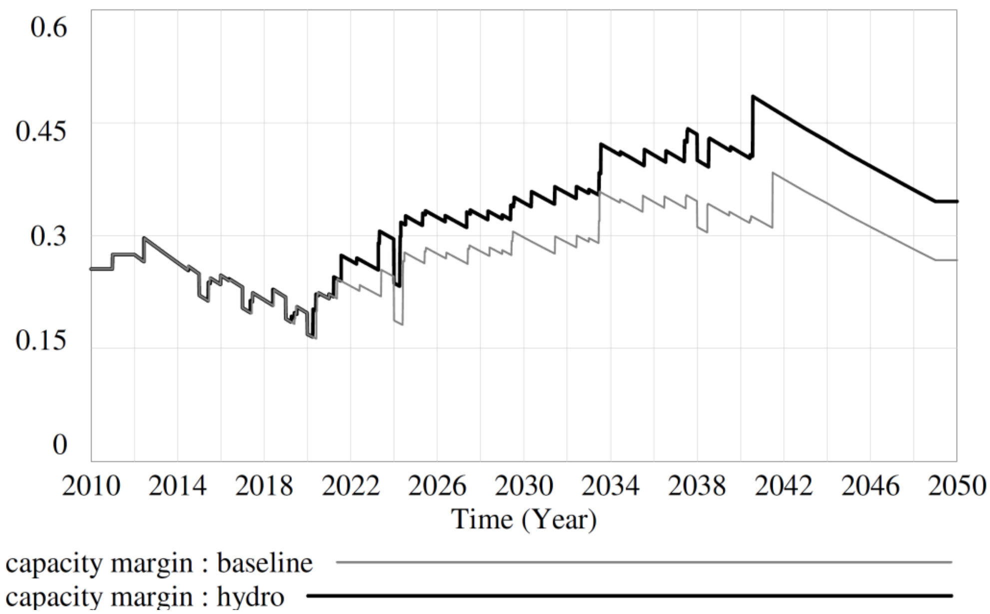

Figure 9.43: Forecasted CM for MDS1

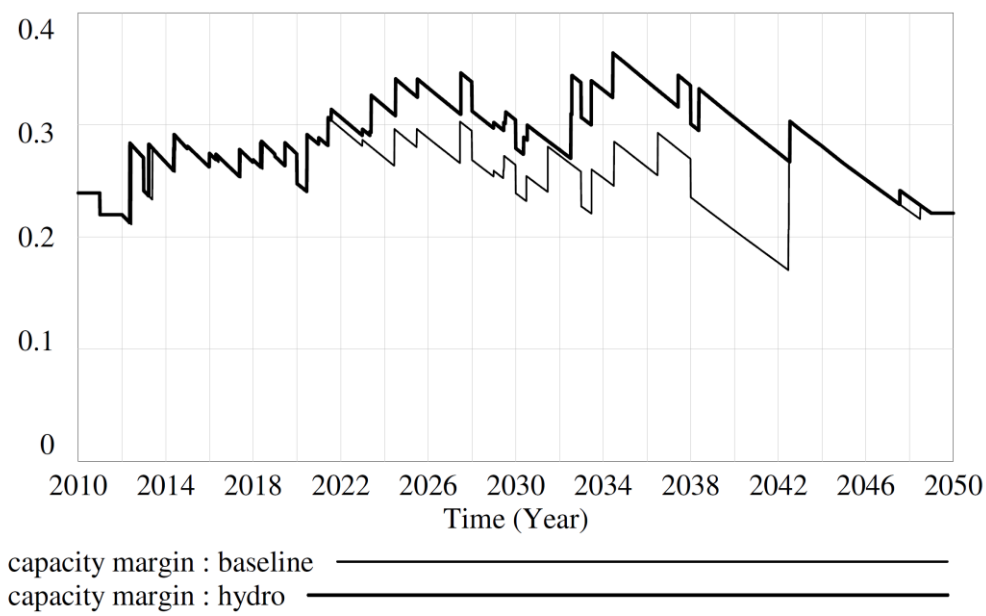

Figure 9.44: Forecasted CM for MDS2

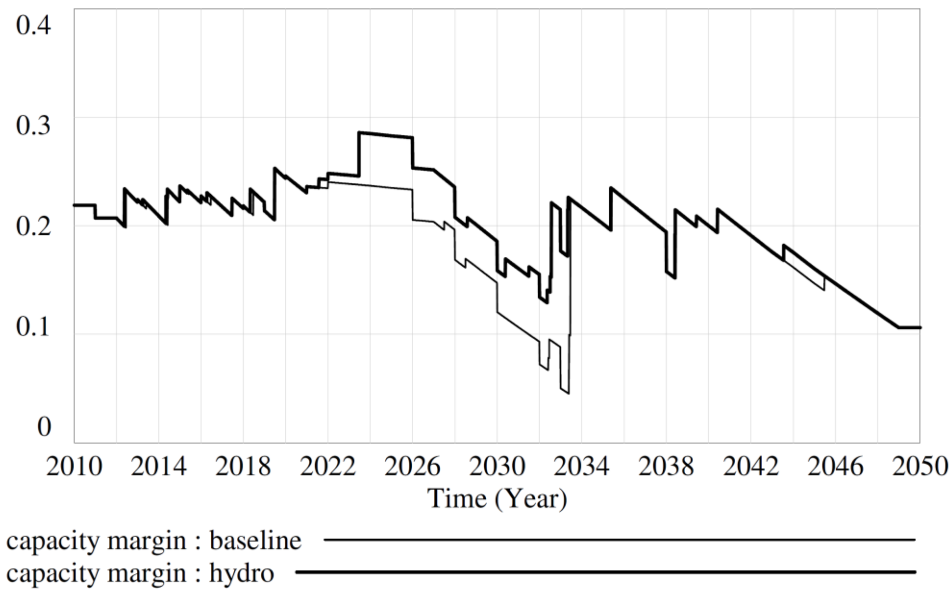

Figure 9.45: Forecasted CM for MDS3

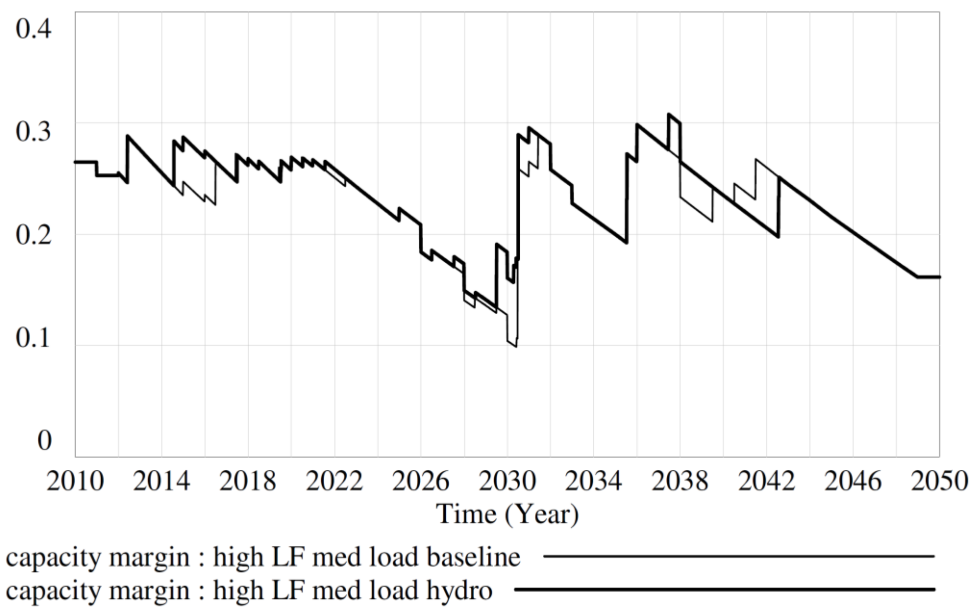

Figure 9.46: Forecasted CM for MDS4

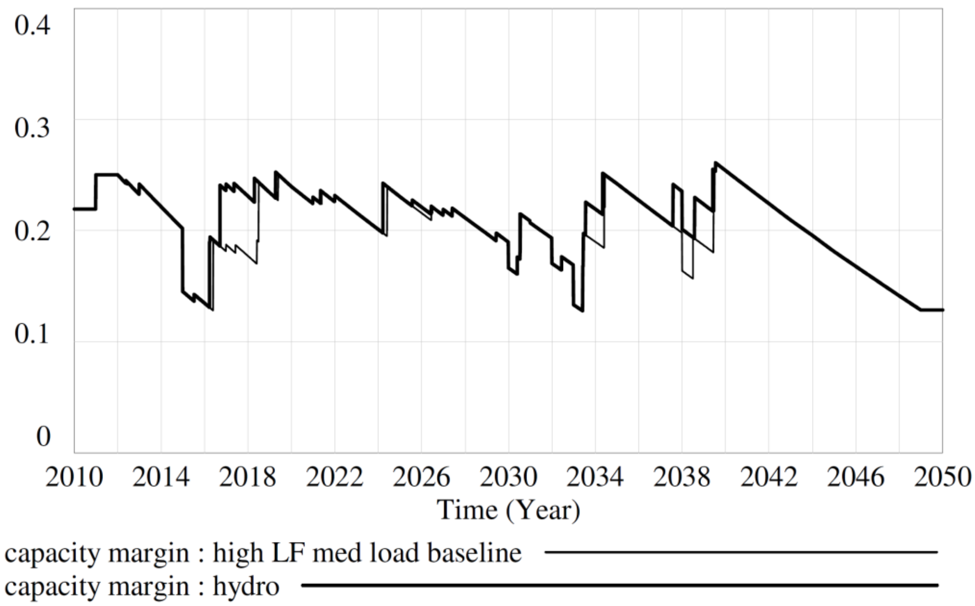

Figure 9.47: Forecasted CM for MDS5

The CM statistics are shown in Table 9.11.

Table 9.11: Summary of CM statistics for the dry year analysis

Scenario	Delays	CM statistics (%)			Security risk predicted?
		Min	Max	Mean	
Sustainable Path (MDS1)	Baseline	16.28	38.36	28.39	No
	Dry years	16.50	48.49	33.35	No
South Island Surplus (MDS2)	Baseline	17.64	33.54	26.18	No
	Dry years	21.26	36.38	28.74	No
Medium Renewables (MDS3)	Baseline	4.49	25.32	18.87	Possibly from 2030-2033 and 2045 if no new plants are scheduled after 2040
	Dry years	10.57	28.56	20.37	Possibly in 2031 and after 2046
Demand-side Participation (MDS4)	Baseline	9.85	28.93	22.44	Possibly between 2028 and 2031
	Dry years	13.42	30.76	23.22	Possibly in 2027
High Gas Recovery (MDS5)	Baseline	12.83	25.50	20.04	Possibly in 2015, 2038 and 2040
	Dry years	12.76	26.08	20.77	Possibly in 2015, 2033 and after 2047

Comparing the results from the two cases for all five scenarios, it can be observed that the CM values are higher when dry years occur. This is because the plants get commissioned much faster when prices rise during dry years.

9.3.6 Dry year analysis summary

Hydro is predicted to continue its domination in New Zealand's generation mix in years to come under all the forecasted scenarios. When hydro plant availability factors decline during dry years, energy shortages are predicted. However, dry years also push prices up and hence cause power plants to become commissioned faster. This results in a higher ability for the system to meet peak demands as indicated by higher capacity margins.

9.4 Chapter summary

This chapter has demonstrated the sensitivities of the SD model outputs to development delays, load growth and dry year occurrences. Development delays act like a damping factor to the boom and bust trends of installed generation capacity. This effect is more visible under MDS with higher large capacity thermal plants. ECMs and CMs are lower when delays are longer, even though the forecasted wholesale electricity prices are sustainably high to encourage investments. This is because it takes a long time for plants to get commissioned. It is therefore important for regulators to ensure that plant developments are not impeded by bureaucratic delays.

High load growth encourages more generation investments as wholesale electricity prices get higher with the smaller margins between supply and demand. However, the smaller margins also reduce the ECMs and CMs and increase the risks of shortages and security breach.

Dry year occurrences cause wholesale electricity prices to increase in dry years with the lower availability of hydro resources. Even though the prices encourage generation investments, it might not encourage the suitable plant type. Having more hydro plants will not improve the dry year shortages unless they are backed up by thermal plants. Severe shortages can occur with a higher percentage of hydro plants in the generation mix. This is the reason why in a regulated ESI with a dominant share of hydro, the regulator ensures that there is a high capacity margin to cater for dry years. In New Zealand, severe shortages can also occur if a dry year coincides with a bust period as predicted in 2015 under MDS5. The simulation results for the dry year analyses emphasise the importance of having a diversified generation mix.

10 CONCLUSIONS AND FURTHER WORK

This chapter concludes the findings from this study and relates them back to its research objectives. It also suggests some potential future work that can be done by others who wish to follow up on this study.

10.1 Conclusions

In the last twenty years, the ESI in many countries have gone through several substantial restructurings. Changes are still being made to the ESI structures to achieve the results promised by a perfect market. It is difficult to decide which structure will work for a country and the results from a wrong decision can be devastating to the country's economy.

One of the difficulties faced by the restructured ESI is to deliver the correct level of generation capacity. Generally, when an ESI is restructured into a retail competition model, boom and bust cycles in generation capacity are observed. Electricity shortages have been observed in several countries during their ESI bust periods. On the other hand, boom periods provide too much excess capacity that defeats the purpose of the restructuring in the first place.

To analyse the boom and bust trends in generation capacity further, this research developed an SD model to study the electricity market and generation expansion in New Zealand. Five different possible future MDS were analysed and the results were discussed in Chapter 8. The SD model predicted that generation capacity cycles will continue to happen in New Zealand under the current market structure. The boom and bust cycles are more obvious under the MDS with large capacity thermal plants in the scheduled generation. During bust periods, energy shortages are predicted as the forecasted energy supply is not sufficient to meet demand. However, with the existing high capacity margin, given the assumed peak load growth, the SD model did not predict much threat to supply security.

Sensitivity analyses were also done to determine the model outputs sensitivities to variations in development delays, load growths and weather factors. Development delays dampen the boom and bust trends of installed generation capacities. Even though the resulting boom and bust pattern looks less obvious with long delays, longer energy shortages are predicted to happen because the investors cannot respond quickly enough to market signals with such a long lead time for development. The impacts of development delays are not too severe on supply security as no breach is predicted by the SD model.

High load growths encourage more installed capacy because the smaller margin between supply and demand pushes up electricity prices. However, more energy shortages are predicted because new power plants do not get commissioned fast enough to meet the demand growth. A high peak load growth can also threaten the supply security.

Weather factors in countries with high dependence on natural resources like New Zealand can have a big impact in generation capacities and supply adequacy. During the occurrence of La Niña, hydro inflows in New Zealand can be reduced, causing low hydro storage levels and as a result, decreases in the hydro generation outputs. Under the MDS where hydro generation remains dominant, shortages are predicted to happen during dry winter years. However, the most severe shortage was predicted under MDS5 (High Gas Recovery scenario) in 2015 when the forecasted dry year coincides with a bust period.

The SD model results highlight the importance of maintaining the correct level of generation supply. The current NZEM structure is unable to encourage the right level of investments that are required by consumers. It is also unclear how the NZEM will encourage the correct generation mix for energy and supply security. New Zealand is keen to increase its renewable portfolios, but thermal plants are still required for periods when renewable resources are low.

In conclusion, this study demonstrated that the SD model is able to evaluate generation supply adequacy under various market development scenarios. This makes SD a potentially useful tool to analyse energy and supply security. The GEM provides some quantitative indication on potential generation capacities. However, without taking into account the dynamics of electricity prices and their relationship with generation capacities, the GEM's predicted generation capacity might not materialise.

Investors will only commit to a plant development when they are certain of their return of investments. On the other hand, an SD model can capture the relationship between electricity prices and generation capacities and potentially produce more realistic results.

10.2 Further work

This research is the first and preliminary attempt at using SD to analyse New Zealand's ESI. Several improvements can be made to enhance the accuracy of the SD model. Some of the improvements and potential results are listed as follows:

1. Refine the inputs of the SD model – Currently the SD model uses the average LRMC for a plant type. With a better knowledge of the actual scheduled power plants, their actual LRMC can be used instead.

2. Improve the forecast of electricity prices – Currently the SD model's equation for the electricity price is simple. Even though prices are difficult to predict, with better modelling techniques in the future, this input can be made more accurate. An accurate price model can include the different prices at different grid nodes and also include the impact of hedging.

3. Improve the forecast of ENSO occurrences – Currently the SD model assumes a 1 in 7 years of ENSO occurrences for its dry year analyses. ENSO is difficult to predict as the prediction is only as good as predicting the weather. When

more research development is done on ENSO predictions, the SD model assumptions can be improved.

4. Include the information on power plants ownership – The information can be used to predict investment behaviour and potentially measure their market power under various MDS.

5. Improve the carbon pricing inputs – This model was developed before the Emission Trading Scheme (ETS) commenced in New Zealand. The carbon pricing inputs were based on the assumptions made by the Electricity Commission as per SOO2008. As the ETS gets more established, better knowledge on it can be gained and the model's carbon pricing inputs can be improved.

6. Extend the SD model to study changes to the NZEM – The SD model can potentially be a useful tool to study the impacts of any suggested change to the NZEM. The SD model was completed before the Ministerial Review 2009 outcomes were published. A good update to the model should include some of the new features introduced under the review.

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APPENDICES

CONTENTS

APPENDIX A: GENERATION TRENDS AFTER ESI RESTRUCTURING

Extracts from "Competitive Electricity Markets and Sustainability" (Lévêque 2006)

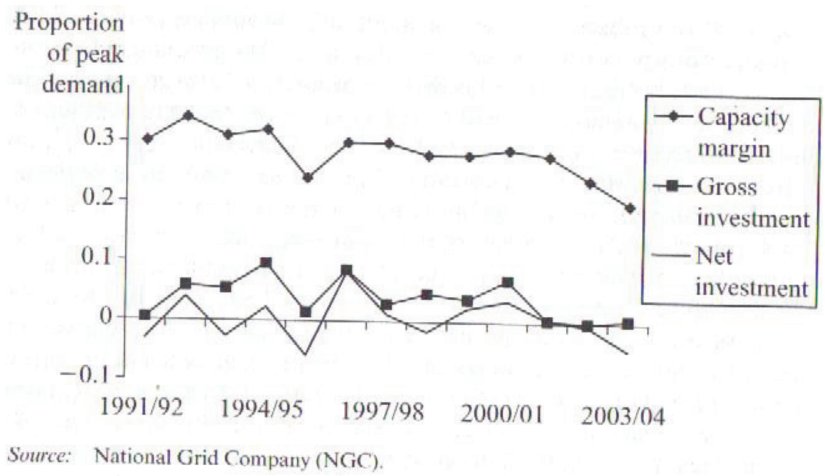


Figure A1: Generation investment in England and Wales from 1991 until 2004

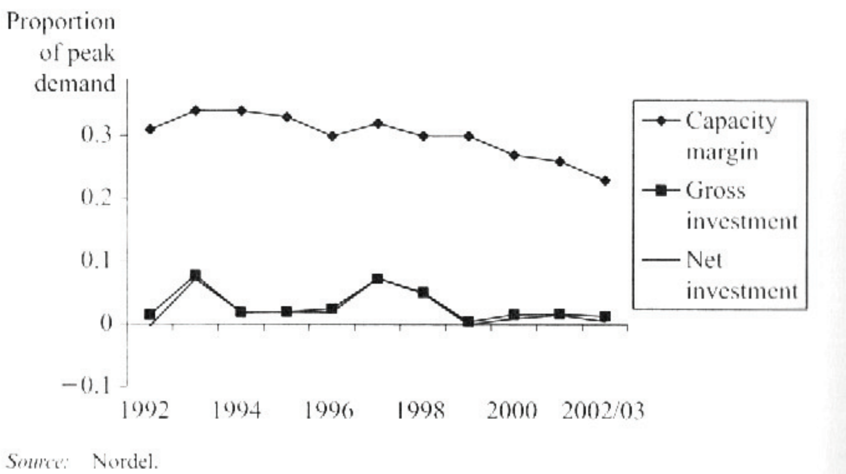
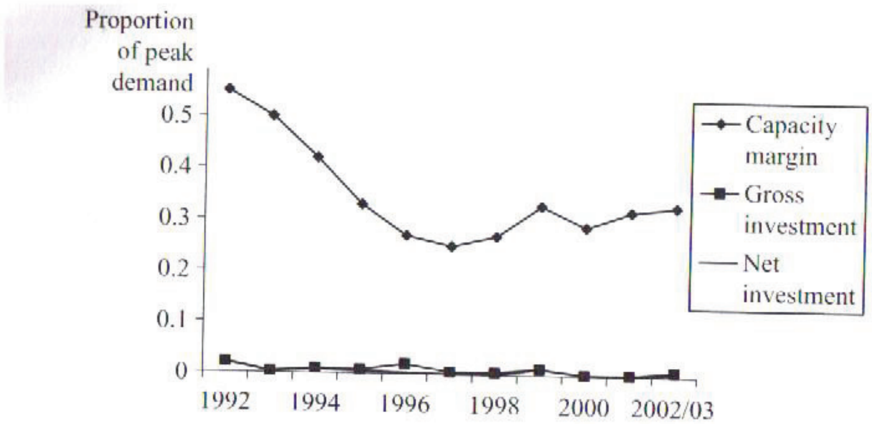
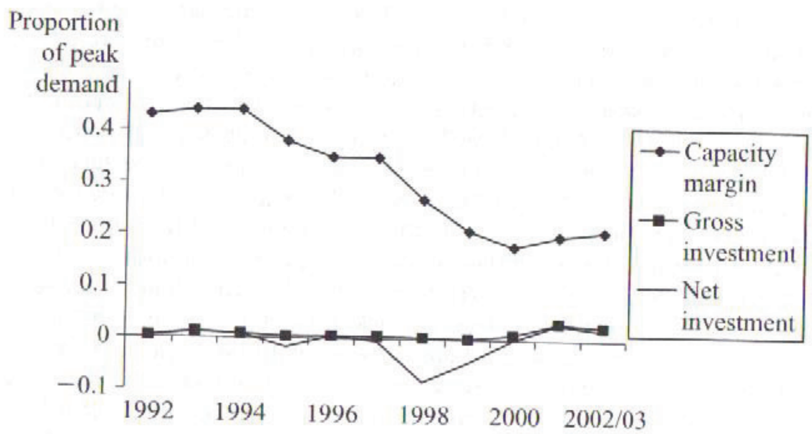


Figure A2: Generation investment in Finland from 1992 until 2000



Source: Nordel.

Figure A3: Generation investment in Norway from 1992 until 2003



Source: Nordel.

Figure A4: Generation investment in Sweden from 1992 until 2003

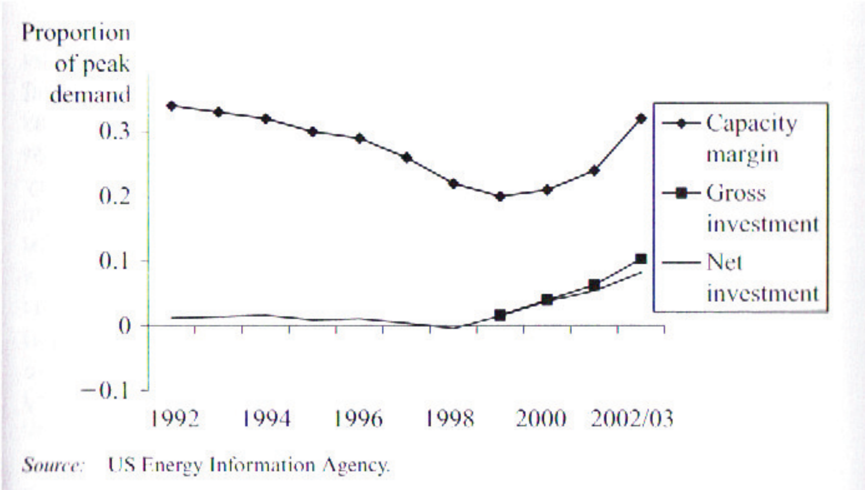


Figure A5: Generation investment in United States from 1992 until 2003

APPENDIX B: INPUT DATA FOR MODEL VALIDATION

B1. Monthly consumption data for January 1997 till December 2009

(Electricity Commission 2010)

Year	Month	Number of days	Monthly consumption (GWh)
997	1	31	2458.754
1997	2	28	2314.218
1997	3	31	2577.483
1997	4	30	2623.997
1997	5	31	2790.681
1997	6	30	2901.497
1997	7	31	3072.357
1997	8	31	3040.332
1997	9	30	2805.177
1997	10	31	2671.482
1997	11	30	2556.784
1997	12	31	2548.49
1998	1	31	2520.142
1998	2	28	2351.794
1998	3	31	2614.215
1998	4	30	2587.149
1998	5	31	2805.599
1998	6	30	2845.223
1998	7	31	2925.3
1998	8	31	2967.82
1998	9	30	2763.014
1998	10	31	2691.369
1998	11	30	2605.821
1998	12	31	2577.08
1999	1	31	2561.53
1999	2	28	2400.205
1999	3	31	2703.603
1999	4	30	2606.412
1999	5	31	2849.061
1999	6	30	2932.696
1999	7	31	3104.297
1999	8	31	3081.716
1999	9	30	2821.844
1999	10	31	2781.308
1999	11	30	2677.502
1999	12	31	2662.3
2000	1	31	2591.449
2000	2	29	2571.209
2000	3	31	2812.329
2000	4	30	2673.844
2000	5	31	2956.777
2000	6	30	2978.37
2000	7	31	3083.92
2000	8	31	3146.738
2000	9	30	2894.337
2000	10	31	2847.378
2000	11	30	2785.735
2000	12	31	2661.744
2001	1	31	2679.139
2001	2	28	2521.43
2001	3	31	2853.461
2001	4	30	2764.241
2001	5	31	3048.614
2001	6	30	3087.584
2001	7	31	3261.291
2001	8	31	2993.493
2001	9	30	2759.498
2001	10	31	2834.587
2001	11	30	2741.619

2001	12	31	2657.558
2002	1	31	2668.817
2002	2	28	2540.836
2002	3	31	2889.182
2002	4	30	2851.258
2002	5	31	3069.292
2002	6	30	3051.277
2002	7	31	3287.366
2002	8	31	3256.811
2002	9	30	3003.428
2002	10	31	3009.753
2002	11	30	2905.935
2002	12	31	2815.536
2003	1	31	2844.383
2003	2	28	2662.154
2003	3	31	2930.957
2003	4	30	2745.181
2003	5	31	2882.004
2003	6	30	2926.591
2003	7	31	3356.202
2003	8	31	3269.659
2003	9	30	3040.393
2003	10	31	3012.545
2003	11	30	2906.154
2003	12	31	2905.965
2004	1	31	2897.737
2004	2	29	2750.189
2004	3	31	3034.746
2004	4	30	2999.413
2004	5	31	3173.26
2004	6	30	3208.443
2004	7	31	3465.985
2004	8	31	3501.976
2004	9	30	3178.703
2004	10	31	3073.563
2004	11	30	2948.629
2004	12	31	2894.832
2005	1	31	2848.261
2005	2	28	2759.201
2005	3	31	3026.373
2005	4	30	2978.213
2005	5	31	3204.31
2005	6	30	3357.341
2005	7	31	3392.272
2005	8	31	3375.5
2005	9	30	3145.324
2005	10	31	3095.361
2005	11	30	2986.894
2005	12	31	2944.94
2006	1	31	2896.316
2006	2	28	2731.709
2006	3	31	3102.118
2006	4	30	2906.514
2006	5	31	3284.766
2006	6	30	3451.675
2006	7	31	3562.36
2006	8	31	3478.331
2006	9	30	3103.488
2006	10	31	3164.545
2006	11	30	2990.948
2006	12	31	2912.96
2007	1	31	2911.957
2007	2	28	2784.663
2007	3	31	3121.043
2007	4	30	3006.867
2007	5	31	3193.308
2007	6	30	3407.298
2007	7	31	3591.258
2007	8	31	3472.072
2007	9	30	3178.949
2007	10	31	3169.478
2007	11	30	3117.438
2007	12	31	3013.099
2008	1	31	3039.837

2008	2	29	2896.636
2008	3	31	3074.649
2008	4	30	3060.1
2008	5	31	3339.104
2008	6	30	3251.468
2008	7	31	3509.86
2008	8	31	3482.334
2008	9	30	3131.321
2008	10	31	3143.309
2008	11	30	2946.993
2008	12	31	2833.37
2009	1	31	2848.715
2009	2	28	2657.528
2009	3	31	2918.675
2009	4	30	2917.041
2009	5	31	3307.757
2009	6	30	3447.896
2009	7	31	3557.432
2009	8	31	3291.607
2009	9	30	3138.928
2009	10	31	3180.435
2009	11	30	3053.875
2009	12	31	3042.411

B2. Monthly averaged price data for Hayward, Benmore and Otahuhu from October 1996 until December 2009 (all prices are in New Zealand Dollars) (MCo 2010)

Year	Hayward	Benmore	Otahuhu
Oct-1996	39.01	31.16	34.78
Nov-1996	42.74	28.17	50.23
Dec-1996	36.45	26.25	42.07
Jan-1997	40.99	31.65	47.74
Feb-1997	49.56	46.05	55.19
Mar-1997	49.92	47.29	53.79
Apr-1997	46.43	43.74	50.43
May-1997	49.17	46.55	52.86
Jun-1997	58.25	57.39	59.01
Jul-1997	57.91	58.18	57.25
Aug-1997	44.02	41.39	47.60
Sep-1997	27.52	25.29	30.79
Oct-1997	38.89	37.11	42.21
Nov-1997	38.75	35.92	43.74
Dec-1997	38.93	33.91	46.59
Jan-1998	41.03	34.91	49.97
Feb-1998	39.11	26.95	49.68
Mar-1998	32.65	17.48	39.67
Apr-1998	32.40	24.26	39.66
May-1998	33.98	29.69	39.75
Jun-1998	33.74	30.86	38.45
Jul-1998	36.31	33.64	42.80
Aug-1998	34.47	32.45	40.41
Sep-1998	35.35	33.11	41.63
Oct-1998	42.19	38.51	50.10
Nov-1998	26.94	25.29	31.70
Dec-1998	32.32	30.52	38.40
Jan-1999	42.08	40.01	54.98
Feb-1999	55.92	52.48	66.62
Mar-1999	61.35	57.19	79.75
Apr-1999	15.30	13.60	18.35
May-1999	26.50	22.06	31.31
Jun-1999	40.53	37.15	45.35
Jul-1999	25.62	23.76	33.63
Aug-1999	31.12	29.57	37.13
Sep-1999	24.73	23.67	27.36
Oct-1999	46.42	45.61	48.84
Nov-1999	16.29	15.20	20.93
Dec-1999	19.32	18.51	21.33
Jan-2000	23.99	22.75	25.64
Feb-2000	25.45	23.74	27.43
Mar-2000	36.65	33.83	38.29
Apr-2000	37.84	35.93	39.96
May-2000	41.03	38.60	45.89
Jun-2000	38.05	34.85	48.52
Jul-2000	28.95	26.58	35.33
Aug-2000	33.29	29.56	44.81
Sep-2000	33.80	30.06	46.78
Oct-2000	25.17	20.46	47.35
Nov-2000	33.80	30.17	53.90
Dec-2000	32.61	28.41	42.87
Jan-2001	35.83	32.67	50.30
Feb-2001	46.28	43.79	50.13
Mar-2001	51.78	50.21	52.91
Apr-2001	67.40	64.61	67.28
May-2001	75.50	74.50	73.92
Jun-2001	166.11	169.71	148.97
Jul-2001	236.79	238.22	219.78
Aug-2001	111.29	127.26	99.25
Sep-2001	55.79	56.41	52.85
Oct-2001	48.97	48.60	48.05
Nov-2001	43.54	42.04	45.91
Dec-2001	16.12	10.58	21.47
Jan-2002	29.83	16.08	37.81
Feb-2002	34.76	32.53	37.97
Mar-2002	44.34	42.59	46.60
Apr-2002	70.75	69.29	69.15
May-2002	58.85	58.18	58.22
Jun-2002	47.35	47.13	45.79
Jul-2002	33.09	32.16	33.81
Aug-2002	34.57	33.66	35.27
Sep-2002	24.64	21.14	28.31
Oct-2002	23.36	15.45	27.96
Nov-2002	30.91	24.91	36.94
Dec-2002	49.41	36.53	61.24

Jan-2003	55.50	45.18	66.13
Feb-2003	87.21	78.13	93.11
Mar-2003	154.29	149.22	160.41
Apr-2003	204.06	199.10	202.25
May-2003	127.61	126.39	122.48
Jun-2003	65.56	63.42	66.83
Jul-2003	58.51	56.20	61.34
Aug-2003	64.81	63.89	64.44
Sep-2003	51.85	50.51	53.03
Oct-2003	32.32	28.68	36.59
Nov-2003	48.45	43.56	54.11
Dec-2003	45.77	41.52	49.44
Jan-2004	69.57	49.06	75.78
Feb-2004	13.56	10.52	16.12
Mar-2004	29.70	10.43	33.90
Apr-2004	46.35	44.16	45.70
May-2004	44.17	42.55	45.54
Jun-2004	33.49	27.22	36.34
Jul-2004	26.10	17.74	28.61
Aug-2004	39.47	26.88	33.11
Sep-2004	29.71	26.74	32.84
Oct-2004	35.81	34.14	37.99
Nov-2004	36.08	34.03	38.01
Dec-2004	40.23	34.59	43.65
Jan-2005	31.18	28.46	34.64
Feb-2005	73.14	64.97	80.16
Mar-2005	62.57	54.42	69.60
Apr-2005	60.90	56.75	64.48
May-2005	70.25	68.88	70.86
Jun-2005	80.07	79.09	78.93
Jul-2005	78.94	78.65	77.02
Aug-2005	73.49	72.04	73.62
Sep-2005	70.29	68.47	70.39
Oct-2005	70.20	70.26	65.68
Nov-2005	103.40	102.31	106.06
Dec-2005	116.20	117.05	117.33
Jan-2006	92.13	90.60	92.98
Feb-2006	101.84	105.54	100.97
Mar-2006	160.75	161.30	155.60
Apr-2006	129.54	135.30	120.75
May-2006	69.37	69.20	67.24
Jun-2006	82.28	80.86	81.66
Jul-2006	69.76	69.92	67.70
Aug-2006	65.53	68.22	60.50
Sep-2006	61.01	61.71	58.25
Oct-2006	49.58	48.19	50.06
Nov-2006	39.34	34.99	42.05
Dec-2006	20.41	15.81	22.00
Jan-2007	25.45	21.52	29.70
Feb-2007	41.10	38.42	43.02
Mar-2007	57.67	55.64	60.25
Apr-2007	61.25	59.09	62.11
May-2007	71.64	71.59	68.85
Jun-2007	68.84	68.75	66.59
Jul-2007	64.29	64.79	61.97
Aug-2007	50.77	51.52	50.18
Sep-2007	52.18	52.25	51.21
Oct-2007	32.67	30.88	33.68
Nov-2007	38.89	35.42	40.75
Dec-2007	57.71	59.08	58.44
Jan-2008	82.28	66.76	83.22
Feb-2008	137.85	126.28	134.85
Mar-2008	128.87	118.17	126.32
Apr-2008	126.24	133.91	119.36
May-2008	271.72	306.78	237.13
Jun-2008	305.95	351.05	265.47
Jul-2008	155.76	170.78	132.64
Aug-2008	118.05	160.10	88.10
Sep-2008	49.40	59.36	46.89
Oct-2008	44.85	40.88	45.23
Nov-2008	47.85	42.94	50.80
Dec-2008	29.52	21.45	33.58
Jan-2009	35.93	9.73	38.93
Feb-2009	41.08	31.05	44.97
Mar-2009	39.02	27.06	43.32
Apr-2009	44.44	31.64	46.72
May-2009	59.18	4.26	59.02
Jun-2009	67.04	32.53	70.06
Jul-2009	60.66	55.02	60.50
Aug-2009	22.71	15.63	24.18
Sep-2009	26.67	9.21	28.88
Oct-2009	39.22	15.16	41.37
Nov-2009	70.57	66.54	70.82
Dec-2009	50.80	46.30	55.52

B3. Electricity Generation Capacity by Plant Types (MW)

Source: Energy Data File (Ministry of Economic Development New Zealand 2009)

December	Electricity Only Plants										Cogen-eration	Total[1]
	Hydro	Geothermal	Biogas	Wind	Fuel Oil	Diesel	Coal/Gas	Gas	Gas/Oil	Sub-total		
1974	3,665	156	-	-	240	180	-	-	-	**4,241**	**76**	**4,317**
1975	3,665	156	-	-	240	180	-	-	-	**4,241**	**83**	**4,324**
1976	3,665	156	-	-	240	180	-	220	600	**5,061**	**83**	**5,144**
1977	3,825	156	-	-	240	180	-	220	600	**5,221**	**83**	**5,304**
1978	3,825	156	-	-	240	494	-	220	600	**5,535**	**88**	**5,622**
1979	4,089	156	-	-	490	494	-	220	600	**6,049**	**88**	**6,137**
1980	4,301	156	-	-	490	494	-	220	600	**6,261**	**88**	**6,349**
1981	4,326	156	-	-	490	494	-	220	600	**6,286**	**107**	**6,393**
1982	4,328	156	-	-	490	494	-	220	600	**6,288**	**107**	**6,394**
1983	4,474	156	-	-	490	494	500	220	600	**6,934**	**107**	**7,041**
1984	4,543	156	-	-	490	494	750	220	600	**7,253**	**107**	**7,360**
1985	4,760	156	-	-	490	494	1,000	220	600	**7,720**	**107**	**7,827**
1986	4,760	156	-	-	490	494	1,000	220	600	**7,720**	**107**	**7,827**
1987	4,760	156	-	-	490	494	1,000	220	600	**7,720**	**143**	**7,863**
1988	4,760	156	-	-	490	314	1,000	220	600	**7,540**	**143**	**7,683**
1989	4,760	273	-	-	490	314	1,000	220	600	**7,656**	**143**	**7,799**
1990	4,760	273	4	-	490	314	1,000	220	600	**7,660**	**143**	**7,803**
1991	4,760	273	7	-	490	314	1,000	220	600	**7,663**	**143**	**7,806**
1992	5,192	273	7	-	250	314	1,000	220	600	**7,855**	**143**	**7,998**
1993	5,192	276	7	0	250	314	1,000	220	600	**7,859**	**143**	**8,003**
1994	5,192	276	7	0	250	314	1,000	220	600	**7,859**	**144**	**8,003**
1995	5,192	276	8	0	250	314	1,000	220	600	**7,861**	**212**	**8,072**
1996	5,192	276	11	4	-	314	1,000	220	600	**7,617**	**217**	**7,834**
1997	5,192	373	11	4	-	-	1,000	220	600	**7,401**	**488**	**7,888**
1998	5,192	383	11	4	-	-	1,000	357	500	**7,448**	**488**	**7,935**
1999	5,199	383	11	36	-	-	1,000	357	400	**7,386**	**483**	**7,869**
2000	5,202	365	11	36	-	-	1,000	737	400	**7,751**	**532**	**8,283**
2001	5,202	365	11	36	-	-	1,000	737	400	**7,751**	**534**	**8,284**
2002	5,342	365	11	36	0	-	1,000	737	400	**7,891**	**518**	**8,409**
2003	5,348	370	18	72	0	-	1,000	737	400	**7,945**	**515**	**8,460**
2004	5,345	370	22	166	0	155	1,000	777	400	**8,236**	**517**	**8,753**
2005	5,346	425	22	168	0	155	1,000	777	300	**8,195**	**556**	**8,751**
2006	5,346	425	23	169	0	155	1,000	787	300	**8,206**	**585**	**8,792**
2007	5,349	443	26	320	0	155	1,000	1,172	300	**8,765**	**631**	**9,396**
2008	5,376	577	27	322	0	155	1,000	1,189	100	**8,746**	**634**	**9,380**

Note:

1) All capacities are net of any plant decommissioning

B4. Monthly generation data for January 2003 till December 2009 (Electricity Commission 2010)

	Plant types												
	Cogeneration	Geothermal	Hydro			Other	Thermal	Wind			Total generation		
Month	NI	NI	NI	SI	Total	NI	NI	NI	SI	Total	NI	SI	NZ
Jan-2003	121	231	457	1645	2102	6	659	14		14	1488	1645	3133
Feb-2003	119	197	403	1296	1699	5	862	12		12	1600	1296	2895
Mar-2003	122	213	404	1382	1786	9	1044	8		8	1799	1382	3181
Apr-2003	111	204	366	1240	1606	6	1052	8		8	1747	1240	2987
May-2003	122	215	375	1219	1594	9	1182	13		13	1916	1219	3134
Jun-2003	99	216	526	1338	1865	8	966	14		14	1830	1338	3168
Jul-2003	112	223	655	1527	2182	9	1082	9		9	2090	1527	3617
Aug-2003	143	226	507	1365	1872	9	1274	9		9	2167	1365	3533
Sep-2003	119	216	615	1359	1974	9	970	14		14	1943	1359	3302
Oct-2003	103	213	731	1641	2372	9	591	12		12	1658	1641	3299
Nov-2003	113	179	582	1601	2183	9	670	16		16	1570	1601	3171
Dec-2003	117	212	587	1501	2088	9	719	15		15	1659	1501	3161
Jan-2004	117	205	552	1474	2026	6	781	12		12	1672	1474	3146
Feb-2004	102	180	750	1517	2266	6	431	14		14	1482	1517	2999
Mar-2004	133	205	711	1733	2444	10	521	16		16	1596	1733	3329
Apr-2004	138	212	521	1387	1908	7	977	15		15	1869	1387	3256
May-2004	117	219	545	1477	2022	8	1057	20		20	1965	1477	3442
Jun-2004	92	221	752	1585	2337	7	814	27		27	1914	1585	3499
Jul-2004	91	229	937	1737	2674	8	744	14		14	2024	1737	3761

Aug-2004	134	227	977	1654	2630	9	803	29		29	2179	1654	3833
Sep-2004	126	222	696	1651	2347	8	755	42		42	1850	1651	3501
Oct-2004	136	210	700	1457	2157	9	807	55		55	1917	1457	3374
Nov-2004	130	204	577	1449	2026	8	795	56		56	1770	1449	3219
Dec-2004	141	225	581	1459	2040	9	725	57		57	1738	1459	3197
Jan-2005	133	215	671	1499	2170	8	565	62		62	1653	1499	3153
Feb-2005	107	198	529	1411	1940	6	712	47		47	1599	1411	3010
Mar-2005	139	220	452	1646	2097	8	816	42		42	1677	1646	3322
Apr-2005	138	215	409	1434	1843	7	998	44		44	1811	1434	3245
May-2005	125	233	444	1420	1863	8	1209	62		62	2081	1420	3501
Jun-2005	110	246	583	1402	1984	7	1261	44		44	2251	1402	3653
Jul-2005	126	249	580	1350	1930	8	1335	54		54	2353	1350	3702
Aug-2005	146	254	510	1403	1913	9	1300	46		46	2266	1403	3669
Sep-2005	125	249	448	1370	1818	8	1172	50		50	2052	1370	3421
Oct-2005	148	229	723	1231	1954	8	1010	41		41	2160	1231	3391
Nov-2005	138	255	542	1249	1791	9	1024	63		63	2030	1249	3278
Dec-2005	143	261	552	1157	1710	9	1053	54		54	2073	1157	3230
Jan-2006	144	255	446	1267	1713	8	997	64		64	1914	1267	3181
Feb-2006	113	227	583	1098	1681	7	908	45		45	1883	1098	2981
Mar-2006	131	243	490	1240	1730	8	1226	49		49	2147	1240	3387
Apr-2006	145	241	469	1053	1522	8	1234	40		40	2137	1053	3190
May-2006	142	263	768	1272	2040	8	1108	23		23	2312	1272	3584
Jun-2006	116	265	790	1355	2144	7	1180	41		41	2399	1355	3753
Jul-2006	105	288	793	1371	2163	8	1241	52		52	2487	1371	3858
Aug-2006	143	286	888	1288	2176	9	1156	44		44	2525	1288	3814
Sep-2006	118	272	617	1199	1816	10	1124	65		65	2205	1199	3404
Oct-2006	124	271	578	1419	1997	10	985	61		61	2027	1419	3447
Nov-2006	133	224	599	1485	2084	9	762	77		77	1804	1485	3289
Dec-2006	136	262	556	1591	2147	9	605	53		53	1620	1591	3211
Jan-2007	133	256	507	1739	2246	9	538	44		44	1488	1739	3226
Feb-2007	121	236	497	1406	1903	9	719	38		38	1620	1406	3026

Mar-2007	120	266	428	1464	1892	10	1038	63		63	1925	1464	3389
Apr-2007	148	263	345	1376	1721	9	1096	41		41	1903	1376	3278
May-2007	141	250	399	1305	1704	10	1312	85		85	2197	1305	3502
Jun-2007	110	272	486	1408	1894	9	1335	72	1	73	2285	1409	3694
Jul-2007	110	286	702	1415	2117	10	1289	90	4	94	2488	1419	3907
Aug-2007	122	289	792	1374	2165	11	1111	97	10	107	2422	1383	3805
Sep-2007	101	286	599	1320	1919	10	1081	67	14	81	2144	1334	3478
Oct-2007	114	303	602	1416	2018	10	924	111	22	133	2064	1438	3501
Nov-2007	108	279	495	1476	1970	10	950	71	15	85	1911	1490	3402
Dec-2007	109	301	439	1356	1795	10	1001	61	11	72	1921	1367	3289
Jan-2008	103	282	389	1387	1776	10	1033	89	16	105	1905	1403	3308
Feb-2008	121	266	380	1324	1703	8	998	61	12	73	1834	1336	3170
Mar-2008	132	288	341	1431	1772	10	1085	65	15	79	1921	1446	3366
Apr-2008	121	285	318	1238	1556		1272	47	9	56	2044	1247	3291
May-2008	149	301	448	1159	1607		1533	42	11	54	2472	1170	3642
Jun-2008	122	268	475	1012	1487		1567	88	18	106	2520	1031	3551
Jul-2008	120	350	760	1159	1919		1317	70	12	82	2617	1171	3788
Aug-2008	126	376	960	1095	2055		1159	73	12	85	2695	1107	3802
Sep-2008	99	374	819	1159	1978		846	74	16	90	2211	1175	3386
Oct-2008	97	352	752	1363	2114		708	97	20	117	2005	1383	3388
Nov-2008	108	354	514	1328	1843		798	72	15	87	1845	1344	3189
Dec-2008	107	382	429	1410	1839		683	75	14	89	1676	1424	3100
Jan-2009	109	363	439	1464	1904		642	86	22	109	1640	1486	3126
Feb-2009	99	323	408	1203	1611		769	69	10	79	1669	1213	2882
Mar-2009	105	370	451	1389	1841		756	83	17	100	1765	1407	3172
Apr-2009	104	363	365	1281	1645		916	65	13	78	1813	1294	3106
May-2009	110	389	460	1559	2019		912	105	10	114	1976	1569	3544
Jun-2009	95	395	520	1498	2018		1065	69	7	76	2145	1505	3650
Jul-2009	98	417	589	1349	1938		1194	96	17	113	2394	1366	3760
Aug-2009	109	393	564	1443	2007		874	112	16	129	2052	1460	3512
Sep-2009	90	365	579	1511	2090		690	116	13	130	1840	1524	3364

Oct-2009	102	385	786	1368	2155		605	146	13	159	2024	1381	3405
Nov-2009	83	331	576	1276	1852		813	155	21	176	1958	1297	3256
Dec-2009	104	355	496	1452	1948		697	156	12	168	1808	1464	3272

B5. Monthly hydro inflows data from January 1996 till June 2008 (Electricity Commission 2010)

month	waikato	waikaremoana	tpd	matahina	mangahao	kaimai	aniwhenua	wheao_flaxy	patea	waitaki	clutha	manapouri	cobb	coleridge	waipori	highbank	branch	Sum(GWh)
Jan-96	390.9	93.5	129.7	29.3	3.4	14.9	11.3	10.8	9.2	1044.6	597.1	331.8	19.4	5.9	16.3	0.0	5.0	2713.1
Feb-96	384.1	58.4	120.5	24.7	11.2	15.1	9.8	9.4	10.0	1054.8	369.4	271.8	7.4	5.2	5.3	10.3	3.6	2371.1
Mar-96	328.6	75.1	115.4	22.8	9.7	14.5	9.0	8.6	8.8	766.5	258.3	179.6	11.2	2.1	10.7	14.9	3.6	1839.4
Apr-96	510.6	84.7	152.9	29.7	19.5	18.0	10.1	9.7	19.6	1111.2	406.1	545.3	17.9	8.5	19.2	16.8	7.3	2987.1
May-96	428.6	58.3	141.7	34.8	17.9	16.2	10.8	10.4	13.0	595.8	338.3	459.2	12.4	16.5	20.1	1.3	3.0	2178.4
Jun-96	397.9	24.2	121.2	31.1	19.3	15.4	10.5	10.1	11.0	388.9	308.4	514.5	19.3	12.5	23.6	19.3	2.7	1929.9
Jul-96	571.7	65.2	154.1	32.2	15.8	19.6	11.1	10.6	22.5	237.0	161.0	149.1	22.5	15.4	22.7	18.9	2.0	1531.2
Aug-96	554.9	37.7	161.2	30.8	14.9	18.6	12.0	11.5	22.5	238.2	132.5	204.5	21.8	14.8	20.7	20.3	3.0	1519.7
Sep-96	671.6	32.3	173.6	38.3	17.4	21.0	12.8	12.3	22.5	396.7	233.0	445.4	22.5	28.9	19.9	14.0	7.5	2169.6
Oct-96	465.2	16.8	157.9	26.7	16.3	17.0	11.6	11.1	14.8	1232.7	709.5	880.3	22.5	28.9	19.7	3.7	9.6	3644.2
Nov-96	408.7	13.8	129.4	22.7	18.7	16.1	10.0	9.6	13.8	713.8	424.8	380.8	22.5	28.9	9.5	3.7	8.5	2235.2
Dec-96	484.3	31.7	159.0	22.7	18.6	17.6	9.8	9.4	17.8	732.5	324.1	440.5	11.0	28.9	4.2	0.1	5.1	2317.3
Jan-97	318.1	23.7	98.9	22.4	5.3	13.7	9.1	8.7	7.4	731.7	269.8	116.6	8.4	24.6	5.3	5.3	2.8	1671.8
Feb-97	293.6	16.3	94.0	19.5	14.1	13.5	8.3	7.9	7.0	975.4	221.4	313.4	7.6	25.1	18.1	7.3	3.2	2045.4
Mar-97	238.6	76.2	64.7	22.4	15.3	11.5	8.1	7.8	2.4	585.4	189.0	258.7	5.3	23.3	22.0	6.5	4.2	1541.4
Apr-97	271.7	23.1	73.5	21.2	15.3	12.1	8.1	7.7	3.5	861.5	335.1	612.1	14.0	26.9	20.6	15.7	3.8	2325.9
May-97	270.1	12.2	76.2	19.5	4.2	12.6	7.5	7.2	6.0	445.4	260.0	370.9	9.2	21.2	28.0	19.1	2.8	1572.1
Jun-97	344.0	93.5	110.7	36.2	7.6	14.3	9.5	9.1	8.5	283.9	203.1	226.1	14.2	19.4	29.9	18.6	3.2	1431.8
Jul-97	333.2	92.0	92.9	29.0	10.7	13.8	9.0	8.6	6.1	263.3	158.1	298.4	6.8	18.1	31.6	18.9	2.0	1392.2
Aug-97	336.4	72.1	98.1	22.8	11.9	14.0	8.0	7.7	8.3	534.0	320.3	644.2	18.0	25.0	22.0	19.8	2.8	2165.2
Sep-97	396.7	52.3	112.5	22.8	15.8	15.5	8.0	7.7	11.9	296.1	231.2	205.3	13.4	17.1	19.6	17.1	2.3	1445.2
Oct-97	398.1	54.8	123.7	26.8	5.6	15.6	8.8	8.4	11.0	500.9	280.6	536.3	14.5	25.7	3.9	9.5	4.6	2028.7

Nov-97	363.2	23.9	105.3	22.0	1.8	14.5	8.2	7.9	8.5	868.4	432.2	931.4	18.6	28.9	1.8	0.0	5.7	2842.3
Dec-97	318.1	7.8	95.9	18.9	0.9	14.2	7.6	7.3	7.6	1288.7	549.9	833.9	16.5	26.3	1.7	0.0	9.3	3204.6
Jan-98	264.0	2.7	76.7	16.0	0.5	12.4	7.2	6.9	6.8	1142.3	423.8	388.7	6.7	28.7	1.2	0.0	3.4	2388.0
Feb-98	283.4	17.9	103.9	16.4	0.6	14.0	7.1	6.8	7.6	1448.2	465.7	786.1	8.2	26.5	0.8	0.0	2.7	3195.9
Mar-98	215.4	7.9	67.4	16.0	1.4	11.8	6.9	6.6	2.9	1360.1	528.6	697.5	11.7	28.4	2.2	3.1	3.4	2971.4
Apr-98	247.6	8.4	71.6	15.8	12.2	12.1	6.9	6.6	3.5	842.2	459.5	710.0	15.6	26.8	6.1	0.2	4.5	2449.5
May-98	319.9	8.0	103.8	16.8	23.0	14.2	6.9	6.6	9.9	550.7	292.1	345.0	13.7	21.5	30.5	16.2	2.8	1781.5
Jun-98	398.1	29.4	122.8	24.7	24.5	15.9	7.3	7.0	13.9	529.6	301.6	516.3	19.0	21.5	37.3	20.4	4.1	2093.5
Jul-98	853.6	93.5	178.6	58.4	23.2	22.9	13.5	12.9	22.5	782.1	364.2	460.2	22.5	28.9	29.0	20.4	9.6	2995.9
Aug-98	495.7	47.0	162.0	39.3	27.4	17.5	13.3	12.7	17.2	510.9	362.8	436.9	18.7	28.9	29.4	20.4	6.4	2246.3
Sep-98	455.9	31.1	153.5	33.2	25.7	16.6	12.6	12.1	13.7	608.1	302.3	564.9	18.9	26.2	16.6	19.7	5.9	2317.0
Oct-98	637.6	29.6	170.4	34.1	28.6	20.9	12.4	11.8	22.5	1355.5	575.1	893.5	22.5	28.8	16.0	15.3	9.6	3884.1
Nov-98	420.1	19.1	145.7	28.9	10.0	16.5	11.9	11.4	16.0	697.0	414.4	223.5	14.3	28.3	11.6	6.9	5.1	2080.5
Dec-98	355.5	29.2	140.6	24.9	22.4	15.0	10.6	10.2	9.6	822.5	266.4	246.7	12.3	28.9	11.0	4.5	2.5	2012.8
Jan-99	288.2	41.9	115.0	21.3	12.1	13.9	8.9	8.5	8.8	789.4	234.7	222.9	4.6	21.8	6.0	1.1	1.8	1800.8
Feb-99	201.3	7.6	69.1	18.4	6.8	10.8	8.1	7.7	1.0	751.2	185.6	135.6	2.8	14.6	3.8	0.0	1.5	1425.9
Mar-99	245.5	6.3	88.6	19.3	3.7	12.8	8.5	8.1	6.7	860.9	242.4	394.8	6.2	14.3	5.0	0.7	2.3	1925.7
Apr-99	249.3	26.1	85.7	20.3	12.9	12.7	8.4	8.0	0.7	680.8	364.7	364.5	17.0	14.5	3.4	13.5	4.0	1886.4
May-99	403.2	40.2	116.2	22.0	24.4	15.3	8.6	8.2	11.8	673.8	348.0	634.0	10.3	18.0	14.4	20.4	3.3	2371.9
Jun-99	433.3	44.4	166.6	31.0	18.0	16.7	8.8	8.5	20.4	447.7	317.0	357.3	17.5	28.2	29.4	20.4	5.2	1970.5
Jul-99	381.9	41.4	136.9	28.3	19.9	16.4	8.7	8.3	16.5	366.6	250.9	381.1	16.1	24.9	25.2	20.4	2.8	1746.2
Aug-99	406.6	43.0	137.3	30.2	18.1	16.3	8.9	8.6	22.2	238.3	165.8	299.7	17.3	19.7	26.6	20.4	2.4	1481.3
Sep-99	400.6	27.9	135.5	32.1	16.0	15.8	9.0	8.6	10.7	350.5	238.0	276.5	17.1	21.1	13.8	19.7	3.1	1596.0
Oct-99	279.2	16.3	93.7	23.5	22.1	13.1	9.0	8.6	1.9	797.7	276.9	457.5	12.9	28.9	14.2	15.3	6.4	2077.1
Nov-99	528.7	36.5	159.6	39.7	25.1	18.8	9.1	8.7	12.2	1724.6	1020.2	846.8	22.5	28.9	2.3	6.9	9.2	4499.9
Dec-99	333.2	34.3	128.0	26.3	21.2	14.3	8.3	7.9	9.2	596.8	418.2	216.6	7.1	17.3	1.3	4.5	2.6	1847.0
Jan-00	312.7	23.7	109.3	21.1	20.2	14.2	8.4	8.1	2.3	1026.7	273.7	184.7	12.3	21.6	8.1	1.1	3.4	2051.3
Feb-00	236.5	7.0	83.3	19.5	8.0	11.7	8.5	8.1	0.7	789.2	268.8	287.2	13.7	28.9	7.7	0.0	3.0	1781.8
Mar-00	163.8	47.2	50.2	16.3	11.0	9.4	7.7	7.4	1.4	456.4	181.2	183.6	2.2	15.0	14.9	0.7	1.5	1169.9
Apr-00	269.4	59.5	99.7	18.7	28.6	13.1	8.0	7.6	6.4	834.7	207.8	290.0	16.2	28.9	21.5	12.3	5.6	1927.9

May-00	269.0	29.0	93.6	19.7	15.3	13.3	7.4	7.1	15.5	579.2	288.4	674.1	12.9	28.8	20.2	20.4	4.1	2098.0
Jun-00	399.5	38.6	131.4	28.1	18.9	15.7	7.5	7.2	18.1	987.0	559.0	687.9	22.5	28.9	27.4	20.4	6.0	3004.0
Jul-00	357.1	81.8	114.4	24.0	17.1	15.0	7.4	7.1	8.7	604.8	452.4	351.5	21.2	27.4	25.4	20.4	4.9	2140.6
Aug-00	376.3	20.3	134.4	26.5	13.1	15.4	8.2	7.9	7.1	412.5	292.5	335.7	20.8	28.9	24.8	20.4	4.4	1748.9
Sep-00	411.3	32.6	144.3	27.0	26.4	16.6	8.8	8.4	22.2	667.0	339.8	507.4	21.0	28.9	27.4	19.7	6.3	2315.0
Oct-00	566.9	35.5	164.4	25.8	28.6	19.0	8.8	8.5	21.0	902.9	532.0	725.2	22.5	28.6	19.1	15.3	9.6	3133.7
Nov-00	312.3	37.3	125.6	20.4	10.0	14.1	9.2	8.8	0.7	535.6	337.5	260.4	9.2	28.9	18.6	6.9	3.3	1738.6
Dec-00	359.3	33.5	124.6	19.7	21.4	15.2	9.1	8.7	4.2	1242.1	403.1	739.3	14.5	28.9	19.7	4.5	3.8	3051.5
Jan-01	266.5	27.1	88.9	19.0	17.8	12.3	8.1	7.8	0.7	751.6	403.9	297.1	10.1	27.5	10.4	1.1	3.3	1953.1
Feb-01	320.2	47.0	116.2	24.0	7.4	14.4	8.3	8.0	1.4	648.6	214.1	205.0	2.8	19.3	25.5	0.0	1.6	1663.7
Mar-01	225.8	20.6	71.9	19.4	15.1	11.3	7.8	7.5	0.7	618.6	171.8	273.0	1.5	9.5	19.6	0.6	1.3	1475.9
Apr-01	221.2	23.5	77.5	23.2	3.9	11.6	7.5	7.2	1.3	338.2	176.8	281.0	4.5	14.5	17.7	11.3	1.5	1222.3
May-01	396.2	25.3	129.5	29.0	15.4	16.2	7.5	7.1	6.3	337.8	148.9	233.3	22.5	13.7	23.8	18.9	2.5	1433.8
Jun-01	328.5	22.9	114.5	22.1	23.8	14.1	7.5	7.2	11.8	417.8	249.2	563.4	16.6	24.6	42.2	20.4	4.4	1891.1
Jul-01	280.4	46.7	92.7	19.5	11.6	13.2	7.6	7.3	8.2	250.1	193.6	160.1	3.5	19.8	46.0	20.4	1.8	1182.3
Aug-01	354.2	56.1	98.4	22.8	26.7	15.0	8.0	7.7	22.5	305.7	196.8	342.2	17.4	23.2	33.2	20.4	2.9	1553.0
Sep-01	275.6	43.7	114.4	22.5	11.0	12.5	8.3	8.0	1.4	292.4	184.5	308.1	8.4	17.5	14.4	19.7	2.9	1345.1
Oct-01	307.0	54.9	109.6	26.1	28.6	14.3	7.8	7.5	8.9	586.3	273.0	341.0	18.8	26.5	3.2	15.3	5.4	1834.2
Nov-01	429.8	49.5	143.6	29.8	28.6	17.0	8.2	7.8	22.5	797.9	316.3	456.7	15.8	28.9	1.1	6.9	7.6	2367.9
Dec-01	635.9	74.9	174.3	42.7	28.6	20.4	11.6	11.2	21.6	1527.0	573.8	497.3	22.5	27.4	1.2	4.5	9.6	3684.5
Jan-02	333.4	19.7	135.4	27.6	20.9	14.3	8.5	8.2	7.1	1488.9	480.3	254.5	11.2	27.8	2.5	1.1	4.1	2845.4
Feb-02	238.7	31.7	87.5	21.1	28.6	11.4	8.1	7.8	9.1	569.8	182.3	248.8	4.8	16.1	1.7	0.0	1.9	1469.3
Mar-02	220.9	10.5	78.3	18.7	28.6	11.3	8.0	7.7	2.8	566.9	195.6	396.6	8.1	19.9	7.8	0.7	3.0	1585.3
Apr-02	240.2	13.4	69.9	19.7	8.1	11.5	7.7	7.4	2.3	466.4	184.6	234.9	6.9	14.7	22.5	12.3	2.2	1324.8
May-02	271.4	15.1	95.0	19.7	10.7	12.9	7.5	7.2	8.3	337.6	175.6	390.5	14.8	13.6	36.1	20.4	2.0	1438.5
Jun-02	464.0	42.6	150.6	27.1	28.0	17.3	8.7	8.3	22.3	649.2	307.4	754.2	22.5	26.1	42.7	18.8	7.6	2597.4
Jul-02	531.7	93.5	160.0	34.9	26.4	17.7	11.6	11.2	18.9	330.3	251.9	332.9	12.2	21.2	27.7	20.8	3.1	1905.9
Aug-02	377.2	66.5	131.8	24.7	15.4	15.0	9.1	8.7	19.7	525.1	293.2	470.8	12.0	23.6	24.1	19.0	2.9	2038.8
Sep-02	424.0	23.9	143.2	21.2	20.0	16.5	8.0	7.6	22.5	803.3	497.4	819.9	22.5	28.9	15.7	9.6	5.9	2890.1
Oct-02	360.0	22.3	122.4	21.1	21.1	14.8	8.0	7.7	11.6	518.0	405.8	447.2	15.9	28.9	14.2	8.2	4.3	2031.3
Nov-02	317.9	16.6	101.2	19.2	20.8	13.9	7.8	7.5	10.1	703.7	377.9	530.7	17.8	28.9	13.7	7.1	6.2	2201.0

Dec-02	396.0	24.6	134.8	19.9	23.1	15.9	8.2	7.9	10.9	1083.5	490.4	681.5	15.1	28.9	6.7	0.9	6.8	2955.1
Jan-03	248.5	8.1	83.7	15.1	5.9	11.7	7.8	7.5	2.4	839.2	331.9	272.1	9.8	25.4	11.6	0.0	3.1	1883.7
Feb-03	174.3	5.4	60.6	12.9	3.9	9.6	7.4	7.1	1.3	808.1	265.1	362.2	6.5	23.6	35.3	0.0	2.3	1785.4
Mar-03	208.4	28.1	73.0	12.7	3.3	11.0	6.9	6.6	0.7	544.5	217.8	176.6	9.8	14.9	23.4	0.5	1.7	1339.9
Apr-03	162.5	26.1	48.1	14.4	3.0	9.6	6.7	6.5	3.2	371.4	124.4	124.2	7.4	15.6	38.4	18.8	2.7	982.9
May-03	294.9	29.3	86.9	15.7	12.7	13.4	6.9	6.6	10.7	813.0	194.3	523.0	13.8	26.3	24.7	21.9	3.7	2097.8
Jun-03	389.9	37.2	133.8	21.6	28.3	15.3	7.3	7.0	22.4	599.2	300.7	662.2	22.5	27.5	15.6	16.7	5.6	2312.6
Jul-03	327.4	29.5	116.0	20.0	18.0	14.1	7.5	7.2	22.5	455.7	321.7	369.6	11.8	24.6	18.6	22.1	4.6	1790.8
Aug-03	241.1	76.6	86.5	14.5	5.8	12.0	7.3	7.0	1.9	244.6	178.9	339.8	13.6	8.6	16.2	21.0	1.8	1277.2
Sep-03	483.9	93.5	151.8	24.6	22.2	17.8	8.1	7.8	22.5	456.6	265.4	647.2	22.5	27.8	12.0	18.4	5.8	2287.8
Oct-03	559.1	56.3	180.5	36.7	17.8	18.9	11.9	11.4	22.4	532.9	360.3	459.5	22.5	28.9	6.8	15.8	8.2	2349.8
Nov-03	395.0	31.9	139.7	22.2	23.3	15.5	9.0	8.6	9.9	730.6	421.9	713.3	17.5	28.9	3.1	2.3	7.1	2579.8
Dec-03	433.9	36.1	145.4	29.5	28.6	16.7	11.2	10.8	12.8	937.7	415.1	479.6	8.0	28.7	1.3	0.0	5.0	2600.2
Jan-04	294.6	31.6	85.8	26.0	13.6	12.5	11.0	10.6	10.4	1284.8	401.6	433.6	6.2	26.4	1.5	0.0	4.7	2654.7
Feb-04	611.9	30.8	197.1	26.6	28.6	19.8	9.2	8.8	22.5	1013.9	379.4	566.4	12.9	20.1	2.6	1.5	7.1	2959.0
Mar-04	400.5	14.9	134.7	25.3	15.4	15.1	10.0	9.6	13.6	1001.8	384.7	366.8	4.7	14.8	3.3	0.6	3.9	2419.7
Apr-04	251.2	8.8	91.9	17.0	11.8	12.1	8.4	8.0	7.0	386.3	213.1	283.8	8.1	13.3	12.0	1.7	1.8	1336.2
May-04	363.3	62.5	123.7	21.8	11.9	15.0	7.6	7.3	13.8	690.8	322.5	502.0	21.3	25.4	16.6	4.5	3.3	2212.9
Jun-04	584.4	66.3	149.3	36.7	28.6	18.8	10.5	10.0	22.5	559.7	363.0	762.7	22.5	25.3	18.8	21.6	7.9	2708.3
Jul-04	505.6	93.5	164.3	58.4	12.6	17.8	12.9	12.4	15.2	347.1	303.5	243.0	14.4	17.6	20.5	22.1	3.5	1864.4
Aug-04	517.6	67.0	176.7	40.1	25.5	18.1	13.5	12.9	22.5	380.9	245.8	379.2	18.7	21.0	22.6	17.6	4.1	1983.7
Sep-04	416.3	29.7	152.5	30.3	28.6	15.9	13.0	12.5	14.5	404.6	280.5	514.1	22.5	26.8	14.9	19.9	4.6	2001.1
Oct-04	530.8	48.7	180.0	33.7	28.6	19.0	13.6	13.0	17.7	504.2	303.0	352.5	22.2	28.9	8.6	18.7	8.2	2131.4
Nov-04	377.5	18.1	123.4	29.1	17.9	15.6	14.3	13.8	3.8	858.9	427.0	504.3	11.7	28.9	3.1	0.9	5.9	2454.1
Dec-04	412.7	22.3	125.8	26.6	28.6	15.6	10.7	10.3	7.6	725.0	376.6	375.6	14.7	23.6	50.3	0.0	4.6	2230.3
Jan-05	383.1	17.1	134.6	32.3	28.6	15.6	11.7	11.2	8.3	1009.3	466.5	401.1	10.1	23.8	17.3	0.0	4.3	2574.7
Feb-05	268.5	8.8	94.6	21.0	9.3	12.7	8.1	7.8	0.7	887.2	305.5	409.4	2.6	22.9	22.5	0.0	2.8	2084.4
Mar-05	238.2	35.5	80.8	19.8	9.4	11.8	8.3	8.0	4.0	781.4	338.5	569.1	9.1	20.8	17.8	0.0	3.9	2156.4
Apr-05	169.8	16.9	53.0	17.8	5.1	9.2	8.2	7.8	5.0	368.5	208.9	253.3	2.9	14.8	23.2	12.4	2.6	1179.5
May-05	290.0	44.6	92.2	23.5	22.6	13.7	7.6	7.3	18.1	372.7	218.3	494.1	11.9	14.3	29.5	17.0	1.7	1679.1
Jun-05	311.8	55.3	107.9	24.9	14.6	13.9	7.5	7.2	13.7	299.2	187.1	342.9	15.2	12.7	35.4	16.1	3.0	1468.3

Jul-05	383.0	44.4	112.1	25.7	23.4	15.6	7.4	7.1	19.4	302.5	185.3	406.6	22.5	15.8	28.5	15.5	3.4	1618.1
Aug-05	342.6	26.0	98.4	22.0	14.7	14.2	7.5	7.2	9.3	355.1	224.7	389.2	18.7	15.1	22.9	17.5	3.3	1588.3
Sep-05	351.6	34.0	103.9	24.3	13.6	14.4	7.6	7.3	8.1	696.8	327.4	301.1	7.6	24.3	11.4	12.5	2.6	1948.3
Oct-05	529.2	91.8	170.2	28.4	15.9	19.4	8.6	8.2	22.5	415.4	231.1	259.5	9.9	17.7	15.1	9.0	2.6	1854.4
Nov-05	251.7	69.2	71.5	20.9	7.9	11.7	8.4	8.1	1.4	542.6	236.1	318.3	3.2	15.9	13.7	0.0	2.1	1582.5
Dec-05	409.0	32.0	131.0	24.3	22.8	16.5	8.0	7.7	10.3	725.3	229.8	240.6	8.0	23.0	9.9	0.0	1.9	1900.1
Jan-06	332.6	20.6	90.6	23.3	15.6	13.8	7.9	7.6	1.3	898.5	314.6	751.1	13.2	23.6	20.4	0.0	4.0	2538.5
Feb-06	338.6	20.1	107.5	28.9	9.1	13.7	8.1	7.8	1.4	579.0	177.2	184.1	5.4	14.7	11.1	0.0	2.4	1508.9
Mar-06	227.9	39.9	57.8	19.8	9.4	10.7	8.0	7.6	0.6	410.0	177.9	317.1	4.2	10.1	21.9	0.0	1.4	1324.1
Apr-06	384.4	60.9	121.4	22.1	15.4	16.0	7.7	7.4	5.5	798.9	252.2	334.9	22.5	27.3	13.2	4.0	7.0	2100.6
May-06	391.7	70.6	120.9	36.6	26.4	15.7	8.5	8.1	7.5	502.6	270.1	279.2	16.5	24.1	18.7	21.1	4.2	1822.3
Jun-06	400.8	93.5	115.9	38.5	28.6	15.6	9.3	8.9	17.2	531.5	254.7	281.1	17.3	28.9	22.6	21.4	4.3	1889.8
Jul-06	479.0	73.2	147.0	31.9	22.9	15.1	13.2	12.7	22.5	320.9	180.3	355.4	19.3	27.1	18.5	22.1	2.4	1763.3
Aug-06	574.7	58.2	156.7	41.4	19.0	18.4	15.0	14.4	22.5	312.8	168.5	356.5	16.9	23.0	16.5	21.9	1.9	1838.3
Sep-06	334.1	26.0	99.5	24.7	27.1	13.1	12.7	12.2	11.0	521.6	285.4	700.7	13.6	23.2	12.2	1.8	3.3	2122.3
Oct-06	318.0	22.5	97.4	22.0	28.6	12.8	10.6	10.2	10.9	750.7	401.8	488.1	16.0	27.5	10.8	6.0	5.0	2238.8
Nov-06	471.7	27.4	150.2	24.9	28.6	14.3	10.4	10.0	22.5	1378.0	475.3	705.5	13.4	28.5	3.2	10.8	9.6	3384.3
Dec-06	331.5	24.3	106.0	19.9	19.3	11.6	9.3	8.9	13.7	961.6	500.4	377.6	12.0	26.1	1.8	16.0	4.9	2444.6
Jan-07	346.6	21.4	109.0	25.0	11.0	15.2	9.0	8.6	6.3	888.2	330.9	318.3	8.4	28.9	0.1	16.1	2.8	2145.7
Feb-07	222.2	9.6	63.6	18.4	7.6	12.3	7.6	7.2	3.9	652.5	243.4	188.0	12.4	24.5	6.5	0.1	2.1	1482.0
Mar-07	250.0	7.2	68.9	16.4	23.6	13.3	5.9	5.7	6.8	573.0	215.0	341.7	12.2	10.8	14.7	2.5	1.4	1569.0
Apr-07	191.5	4.8	55.8	15.9	5.9	13.9	5.8	5.6	4.1	363.8	166.2	189.9	15.9	17.9	22.5	1.4	1.3	1082.2
May-07	223.3	11.2	74.8	15.8	16.3	14.6	5.2	5.0	6.0	414.0	217.3	614.7	17.7	15.9	38.3	9.5	3.1	1702.8
Jun-07	316.2	39.1	89.7	14.9	11.6	13.1	4.8	4.6	12.4	421.4	305.8	304.7	16.8	16.5	32.6	19.5	2.6	1626.3
Jul-07	471.3	93.5	149.6	23.4	21.1	19.9	6.3	6.1	20.5	392.2	248.1	427.0	20.1	20.4	30.8	19.9	3.9	1974.1
Aug-07	532.1	29.8	169.2	27.4	24.7	20.2	7.6	7.2	22.5	317.0	257.3	527.4	19.7	18.0	21.1	18.4	2.7	2021.9
Sep-07	326.3	37.8	98.2	18.6	12.3	15.7	6.8	6.5	7.8	364.3	240.9	445.2	17.3	14.2	18.4	12.0	2.5	1645.0
Oct-07	422.1	41.3	132.7	19.5	25.5	16.7	6.8	6.5	22.0	753.3	431.4	803.7	17.7	22.8	11.5	15.8	9.6	2758.8
Nov-07	297.3	12.3	90.1	15.5	23.0	12.1	6.3	6.0	4.1	553.3	360.0	300.4	19.4	27.0	4.6	0.6	5.2	1737.2
Dec-07	310.8	23.6	100.9	15.3	3.5	12.8	5.6	5.4	5.4	1011.5	356.0	314.7	10.5	19.5	12.3	0.0	4.1	2212.1
Jan-08	177.2	13.7	52.7	12.9	19.4	10.2	4.8	4.6	2.8	838.4	310.7	275.9	10.0	22.7	11.1	0.0	3.7	1770.5

Feb-08	152.6	3.7	39.8	11.5	6.3	10.0	4.0	3.8	1.4	727.4	219.4	254.0	13.8	26.6	31.4	7.2	3.4	1516.3
Mar-08	161.6	26.6	42.1	11.4	6.1	10.5	3.5	3.4	2.2	671.8	252.7	327.7	6.4	21.6	17.3	4.3	3.9	1573.0
Apr-08	273.7	49.8	84.8	18.4	10.7	14.9	3.3	3.2	10.2	380.5	157.4	155.9	7.6	15.8	11.0	2.5	2.4	1201.7
May-08	284.8	65.0	97.3	20.7	7.8	15.7	4.6	4.4	16.9	308.9	152.5	205.5	6.4	20.8	27.7	10.7	2.3	1251.9
Jun-08	330.4	50.9	96.8	17.3	20.5	16.3	4.0	3.8	13.8	329.8	183.8	365.0	6.6	15.6	18.6	19.3	2.1	1494.9

APPENDIX C: INPUTS TO THE SOO2008 & SD MODEL

C1. Existing grid connected power plants (Electricity Commission 2008)

Name	Type	MW	Region
Arapuni	Hydro	197	Waikato
Aratiatia	Hydro	78	Waikato
Argyle	Hydro	4	Nelson
Atiamuri	Hydro	84	Bay Of Plenty
Aviemore	Hydro	220	South Canterbury
Benmore	Hydro	540	South Canterbury
Clyde	Hydro	432	Otago/Southland
Cobb	Hydro	32	Nelson
Coleridge	Hydro	45	Canterbury
Huntly	Thermal	1,000	Waikato
Huntly e3p	Thermal	385	Waikato
Huntly p40	Thermal	50	Waikato
Kaitawa	Hydro	36	Hawke's Bay
Karapiro	Hydro	90	Waikato
Manapouri	Hydro	710	Otago/Southland
Mangahao	Hydro	42	Central
Maraetai	Hydro	360	Waikato
Matahina	Hydro	72	Bay of Plenty
Mokai I and II	Geothermal	112	Waikato
Mokai III	Geothermal	17	Waikato
Ohaaki	Geothermal	40	Waikato
Ohakuri	Hydro	112	Waikato
Ohau A	Hydro	264	South Canterbury
Ohau B	Hydro	212	South Canterbury
Ohau C	Hydro	212	South Canterbury
Otahuhu B	Thermal	380	Auckland
Patea	Hydro	31	Taranaki
Piripaua	Hydro	42	Hawke's Bay
Poihipi Rd	Geothermal	55	Waikato
Rangipo	Hydro	120	Central
Roxburgh	Hydro	320	Otago/Southland

Name	Type	MW	Region
Southdown	Thermal	170	Auckland
Tararua Stage 3	Wind	93	Central
Taranaki Combined Cycle (TCC)	Thermal	385	Taranaki
Te Apiti	Wind	90	Central
Tekapo A	Hydro	25	South Canterbury
Tekapo B	Hydro	160	South Canterbury
Tokaanu	Hydro	240	Central
Tuai	Hydro	60	Hawke's Bay
Waipapa	Hydro	51	Waikato
Waipori*	Hydro	84	Otago/Southland
Wairakei	Geothermal	161	Waikato
Wairau	Hydro	7	Nelson
Waitaki	Hydro	105	Otago/Southland
Whakamaru	Hydro	100	Waikato
Wheao and Flaxy Scheme	Hydro	24	Bay of Plenty
Whirinaki	Thermal	155	Hawke's Bay
Glenbrook	Co-generation	112	Auckland
Kapuni	Co-generation	25	Taranaki
Kawerau pulp and paper	Co-generation	37	Bay of Plenty
Kinleith	Co-generation	40	Waikato
Whareroa (Kiwi Dairy)	Co-generation	70	Taranaki
Total		**8,488**	

* Some generating units at Waipori are grid-connected, others are embedded within the local lines network, and some can be switched between both.

C2. Existing significant embedded generation (Electricity Commission 2008)

Name	Type	MW	Region
Aniwhenua	Hydro	25	Bay of Plenty
Bay Milk Edgecumbe	Co-generation	10	Bay of Plenty
Highbank	Hydro	25	Canterbury
Kaimai scheme	Hydro	42	Bay of Plenty
Ngawha	Geothermal	10	North Isthmus
Paerau Gorge scheme	Hydro	12	Otago/Southland
Rotokawa	Geothermal	33	Waikato
Tararua Stages 1 + 2	Wind	68	Central
Te Rapa	Co-generation	44	Waikato
Teviot scheme	Hydro	15	Otago/Southland
White Hill	Wind	58	Otago/Southland
Total		**342**	

C3. Build schedules and corresponding capacity stackplots for the five scenarios

Table A1: Build schedules for Sustainable Path (MDS1)

Year	Plant description	Technology description	MW
2008	Deep Stream	Hydro, run of river	6
2009	Generic OCGT NI 1	Peaker, diesel-fired OCGT	150
	Ngawha 2	Geothermal	15
	Kawerau stage 1	Geothermal	90
	Te Rere Hau	Wind	49
	West Wind	Wind	143
2010	Rotokawa 2	Geothermal	130
	Te Waka	Wind	102
	Titiokura	Wind	45
2011	Wairakei	Geothermal	-163
	Te Mihi	Geothermal	220
	Hawea Control Gate Retrofit	Hydro, peaking	17
	Wairau	Hydro, run of river	73
2013	Generic OCGT NI 4	Peaker, diesel-fired OCGT	150
	Generic OCGT NI 5	Peaker, diesel-fired OCGT	150
2014	Mokai 4	Geothermal	40
	Mohaka	Hydro, run of river	44
2015	Huntly coal unit 1	Coal	-226
	Tauhara stage 2	Geothermal	200
	Kakapotahi	Hydro, run of river	17
	Toaroha	Hydro, run of river	25
	Otoi Waiau	Hydro, run of river	17
2016	Tauhara stage 1	Geothermal	20
	Demand-side response 1 NI	Price-responsive load curtailment	100
2017	Huntly coal unit 2	Coal	-226
	Gas fired OCGT 1	Peaker, fast start gas-fired peaker	200
	Kawerau stage 2	Geothermal	67

Year	Plant description	Technology description	MW
	Rotokawa 3	Geothermal	67
	Clutha River Luggate	Hydro, peaking	100
2018	Clutha River Queensberry	Hydro, peaking	180
2019	Huntly coal unit 3	Coal	-226
	Huntly gas	Open cycle gas turbine – gas	-66
	Generic OCGT NI 2	Peaker, diesel-fired OCGT	150
	Ngatamariki	Geothermal	67
	Mangawhero to Wanganui Div	Hydro, run of river	60
	Lake Mahinerangi	Wind	200
	New IL 1	Interruptible load	50
2020	Huntly coal unit 4	Coal	-226
	Marsden Point Refinery	Co-generation, gas-fired	85
	Ngawha 2	Geothermal	-15
	Biomass Cogen, Kawerau	Co-generation, biomass-fired	30
	Clutha River Beaumont	Hydro, peaking	190
	Rototuna Forest	Wind	250
	Ohariu Valley	Wind	70
2021	Motorimu	Wind	80
	Turitea	Wind	150
	Demand-side response 2 NI	Price-responsive load curtailment	50
2022	Taranaki CC	Combined cycle gas turbine	-360
	TCC – in limited operation	Combined cycle gas turbine	360
	Gas fired OCGT 2	Peaker, fast start gas-fired peaker	200
	Long Gully	Wind	70
2023	Huntly P40	Open cycle gas turbine – gas	-50
	Generic OCGT NI 3	Peaker, diesel-fired OCGT	150
	Generic wind Waikato 2	Wind	200
	Puketiro	Wind	120
	New IL 2	Interruptible load	50
2024	Southdown	Combined cycle gas turbine	-122
	TCC – in limited operation	Combined cycle gas turbine	-360
	Southdown E105	Open cycle gas turbine – gas	-45

Year	Plant description	Technology description	MW
	Generic OCGT NI 6	Peaker, diesel-fired OCGT	150
	Generic geo 2	Geothermal	110
	Biomass Cogen, Central	Co-generation, biomass-fired	30
	Biomass Cogen, Whirinaki	Co-generation, biomass-fired	30
	Whakapapanui Papamanuka	Hydro, run of river	16
	Whangaehu	Hydro, run of river	20
	Clarence to Waiau Diversions	Hydro, run of river	70
	Waitangi Falls Ruakiteri	Hydro, run of river	16
	Kaituna Low Level	Hydro, run of river	38
	Tarawera at Lake Outlet	Hydro, run of river	14
	Mokairau	Wind	16
	Generic wind Wairarapa 1	Wind	100
	Pouto	Wind	300
	Belmont Hills	Wind	80
2025	Coal seam gas plant	Co-generation, other	50
	Waikato upgrade	Hydro, peaking	150
	Generic wave 1	Wave	50
2026	Generic geo 1	Geothermal	75
2027	Generic geo 3	Geothermal	110
	Te Uku	Wind	84
	Generic wave 2	Wave	50
2028	Tenergy NZ Wind Farm	Wind	10
	Waverley	Wind	100
2029	Lower Clarence River	Hydro, run of river	35
	Wainui Hills	Wind	30
	Red Hill	Wind	20
	Generic wind Wairarapa 2	Wind	100
	Generic wave 3	Wave	50
	Demand-side response 2 SI	Price-responsive load curtailment	50
2030	Glenbrook upgrade	Co-generation, other	80
	Generic pumped hydro	Hydro, pumped storage	300
2031	Project Hayes stage 1	Wind	150

Year	Plant description	Technology description	MW
	Tiwai Peninsula	Wind	80
2032	Project Hayes stage 2	Wind	160
2033	IGCC coal plant with CCS	Coal, IGCC with CCS	400
	New IL 3	Interruptible load	50
2034	Nevis River	Hydro, run of river	45
2035	Generic pumped hydro 2	Hydro, pumped storage	300
	Hawkes Bay Wind Farm	Wind	225
2036	Project Hayes stage 3	Wind	160
2037	Taipo	Hydro, run of river	33
	Project Hayes stage 4	Wind	160
2038	Otahuhu B	Combined cycle gas turbine	-365
	CCGT with CCS 2	Combined cycle gas turbine with CCS	410
	Arahura	Hydro, run of river	18
	Generic wind Taranaki	Wind	100
2039	CCGT with CCS	Combined cycle gas turbine with CCS	410
	Butler River	Hydro, run of river	23
	Upper Grey	Hydro, run of river	35
2040	Arawata River	Hydro, run of river	62
	Mt Cass	Wind	50

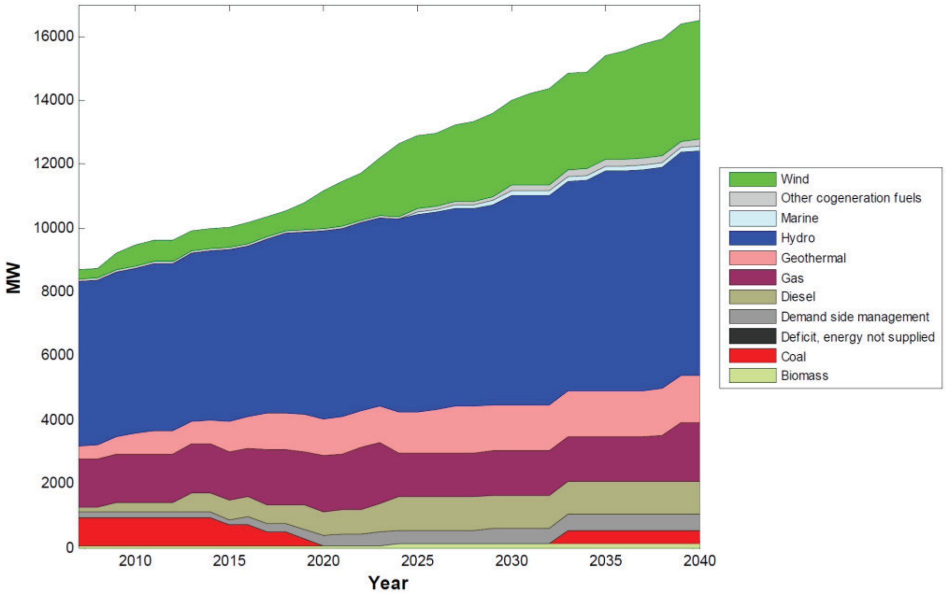


Figure A6: Capacity stackplot by fuel and by year for MDS1 (Sustainable Path) scenario

Table A2: Build schedules for South Island Surplus (MDS2)

Year	Plant description	Technology description	MW
2008	Deep Stream	Hydro, run of river	6
2009	Ngawha 2	Geothermal	15
	Kawerau stage 1	Geothermal	90
2010	Gas fired OCGT 1	Peaker, fast start gas-fired peaker	200
	Te Rere Hau	Wind	49
	Te Waka	Wind	102
	West Wind	Wind	143
2011	Wairakei	Geothermal	-163
	Rotokawa 2	Geothermal	130
	Te Mihi	Geothermal	220
	Hawea Control Gate Retrofit	Hydro, peaking	17
2012	Project Hayes stage 1	Wind	150
	Titiokura	Wind	45
2013	Huntly coal unit 1	Coal	-226
	Generic OCGT NI 1	Peaker, diesel-fired OCGT	150
	Generic OCGT NI 3	Peaker, diesel-fired OCGT	150
	Lake Mahinerangi	Wind	200
	Project Hayes stage 2	Wind	160
2014	Generic OCGT NI 2	Peaker, diesel-fired OCGT	150
	Project Hayes stage 3	Wind	160
2015	Huntly coal unit 2	Coal	-226
	Huntly coal – reserve unit 2	Coal, dry year mode	245
	Demand-side response 1 NI	Price-responsive load curtailment	100
2016	Mokai 4	Geothermal	40
	Clutha River Luggate	Hydro, peaking	100
2017	Tauhara stage 2	Geothermal	200
2018	Huntly coal unit 3	Coal	-226
	Huntly coal – reserve unit 3	Coal, dry year mode	245
	Tauhara stage 1	Geothermal	20
	Clutha River Queensberry	Hydro, peaking	180
2019	Huntly gas	Open cycle gas turbine – gas	-66

Year	Plant description	Technology description	MW
	Gas fired OCGT 2	Peaker, fast start gas-fired peaker	200
	Mokairau	Wind	16
	Motorimu	Wind	80
	Belmont Hills	Wind	80
	New IL 1	Interruptible load	50
2020	Huntly coal unit 4	Coal	-226
	Marsden Point Refinery	Co-generation, gas-fired	85
	Clutha River Beaumont	Hydro, peaking	190
	Long Gully	Wind	70
	Turitea	Wind	150
	Red Hill	Wind	20
	Tenergy NZ Wind Farm	Wind	10
2021	Biomass Cogen, Kawerau	Co-generation, biomass-fired	30
	Puketiro	Wind	120
	Demand-side response 2 NI	Price-responsive load curtailment	50
2022	Generic wind Central	Wind	100
	Demand-side response 2 SI	Price-responsive load curtailment	50
2023	Taranaki CC	Combined cycle gas turbine	-360
	TCC – in limited operation	Combined cycle gas turbine	360
	Biomass Cogen, Central	Co-generation, biomass-fired	30
	Biomass Cogen, Whirinaki	Co-generation, biomass-fired	30
	New IL 2	Interruptible load	50
2024	Generic OCGT NI 4	Peaker, diesel-fired OCGT	150
	Pouto	Wind	300
2025	Coal seam gas plant	Co-generation, other	50
	Waikato upgrade	Hydro, peaking	150
2027	Rototuna Forest	Wind	250
	Generic wave 1	Wave	50
2028	Huntly coal – reserve unit 2	Coal, dry year mode	-245
	Generic OCGT NI 5	Peaker, diesel-fired OCGT	150
	Generic OCGT NI 6	Peaker, diesel-fired OCGT	150
	Generic wind Wairarapa 1	Wind	100

Year	Plant description	Technology description	MW
2029	Nevis River	Hydro, run of river	45
	Ohariu Valley	Wind	70
	New IL 3	Interruptible load	50
2030	Huntly coal – reserve unit 3	Coal, dry year mode	-245
	IGCC coal plant with CCS 2	Coal, IGCC with CCS	400
	Glenbrook upgrade	Co-generation, other	80
2031	Demand-side response 4 NI	Price-responsive load curtailment	50
2033	IGCC coal plant with CCS	Coal, IGCC with CCS	400
	Otahuhu C	Combined cycle gas turbine	407
	TCC – in limited operation	Combined cycle gas turbine	-360
2036	IGCC coal plant with CCS 4	Coal, IGCC with CCS	400
2038	Otahuhu B	Combined cycle gas turbine	-365
	Generic gas 1 Auckland	Combined cycle gas turbine	410
	Generic OCGT NI 7	Peaker, diesel-fired OCGT	150

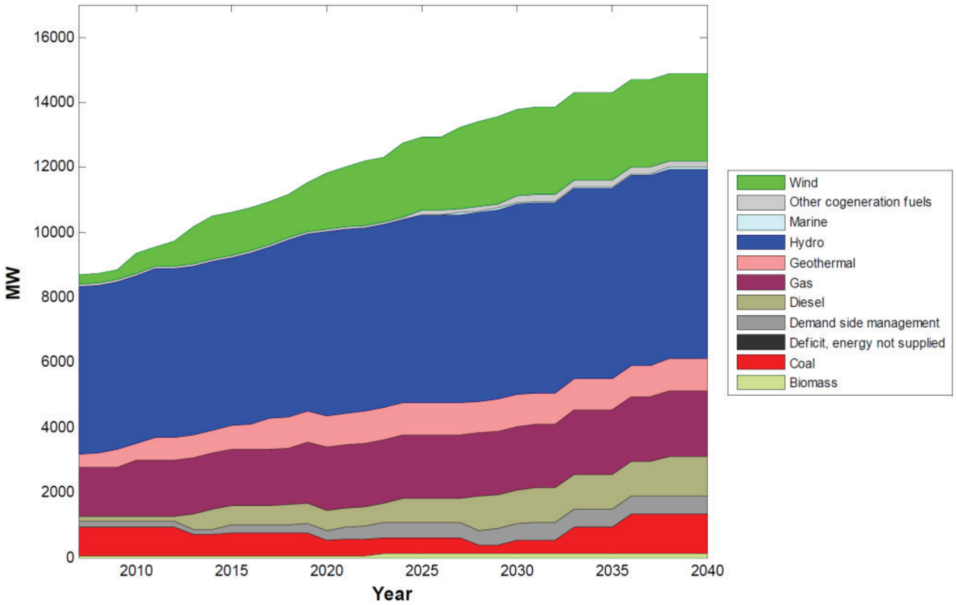


Figure A7: Capacity stackplot by fuel and by year for MDS2 (South Island Surplus) scenario

Table A3: Build schedules for Medium Renewables (MDS3)

Year	Plant description	Technology description	MW
2008	Deep Stream	Hydro, run of river	6
2009	Ngawha 2	Geothermal	15
	Kawerau stage 1	Geothermal	90
	Te Rere Hau	Wind	49
	West Wind	Wind	143
2010	Rotokawa 2	Geothermal	130
	Hawea Control Gate Retrofit	Hydro, peaking	17
	Titiokura	Wind	45
2011	Wairakei	Geothermal	-163
	Te Mihi	Geothermal	220
	Wairau	Hydro, run of river	73
2012	Generic OCGT NI 1	Peaker, diesel-fired OCGT	150
2013	Huntly coal unit 1	Coal	-226
	Huntly coal – reserve unit 1	Coal, dry year mode	245
	Gas fired OCGT 1	Peaker, fast start gas-fired peaker	200
	Mokai 4	Geothermal	40
2014	Tauhara stage 2	Geothermal	200
2015	Huntly coal unit 2	Coal	-226
	Huntly coal – reserve unit 2	Coal, dry year mode	245
	Tauhara stage 1	Geothermal	20
	Mangawhero to Wanganui Div	Hydro, run of river	60
	Demand-side response 1 NI	Price-responsive load curtailment	100
2016	Kawerau stage 2	Geothermal	67
	New IL 1	Interruptible load	50
2017	Generic OCGT NI 6	Peaker, diesel-fired OCGT	150
	Ngatamariki	Geothermal	67
	Rotokawa 3	Geothermal	67
2018	Huntly coal unit 3	Coal	-226
	Huntly coal – reserve unit 3	Coal, dry year mode	245
	Clutha River Queensberry	Hydro, peaking	180
	Long Gully	Wind	70

Year	Plant description	Technology description	MW
2019	Otahuhu C	Combined cycle gas turbine	407
	Huntly gas	Open cycle gas turbine – gas	-66
2020	Huntly coal unit 4	Coal	-226
	Huntly coal – reserve unit 4	Coal, dry year mode	245
2021	New IL 2	Interruptible load	50
2022	Demand-side response 2 NI	Price-responsive load curtailment	50
2026	Huntly coal – reserve unit 1	Coal, dry year mode	-245
	Generic OCGT NI 2	Peaker, diesel-fired OCGT	150
	Generic OCGT NI 3	Peaker, diesel-fired OCGT	150
2027	Generic OCGT NI 4	Peaker, diesel-fired OCGT	150
2028	Huntly coal – reserve unit 2	Coal, dry year mode	-245
	Gas fired OCGT 2	Peaker, fast start gas-fired peaker	200
2029	Generic geo 1	Geothermal	75
2030	Huntly coal – reserve unit 3	Coal, dry year mode	-245
	Coal seam gas plant	Co-generation, other	50
	Generic pumped hydro	Hydro, pumped storage	300
2031	Glenbrook upgrade	Co-generation, other	80
2032	Huntly coal – reserve unit 4	Coal, dry year mode	-245
	Marsden Point Refinery	Co-generation, gas-fired	85
	Demand-side response 4 NI	Price-responsive load curtailment	50
2033	Generic gas 1 Auckland	Combined cycle gas turbine	410
	Taranaki CC	Combined cycle gas turbine	-360
	Generic geo 2	Geothermal	110
2034	Generic geo 3	Geothermal	110
2035	Taranaki CC 2	Combined cycle gas turbine	380
2038	Otahuhu B	Combined cycle gas turbine	-365
	Generic gas 2 Taranaki	Combined cycle gas turbine	410
	Generic OCGT NI 5	Peaker, diesel-fired OCGT	150
	Motorimu	Wind	80
	Turitea	Wind	150
2039	Waverley	Wind	100
2040	Hawkes Bay Wind Farm	Wind	225

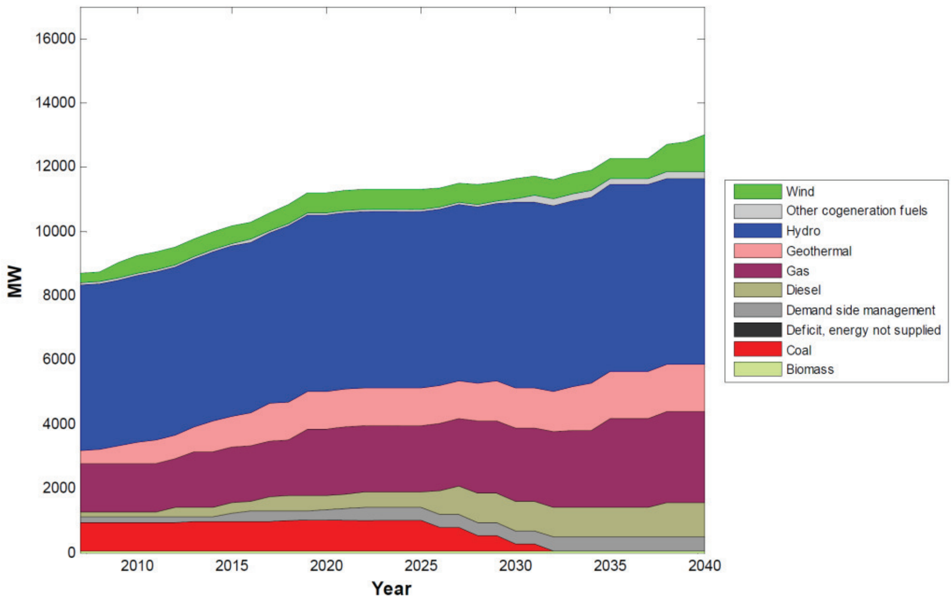


Figure A8: Capacity stackplot by fuel and by year for MDS3 (Medium Renewables) scenario

Table A4: Build schedules for Demand Side Participation (MDS4)

Year	Plant description	Technology description	MW
2008	Deep Stream	Hydro, run of river	6
2009	Generic OCGT NI 1	Peaker, diesel-fired OCGT	150
	Ngawha 2	Geothermal	15
	Kawerau stage 1	Geothermal	90
	Te Rere Hau	Wind	49
2010	Gas fired OCGT 1	Peaker, fast start gas-fired peaker	200
	Rotokawa 2	Geothermal	130
	West Wind	Wind	143
2011	Wairakei	Geothermal	-163
	Te Mihi	Geothermal	220
	Wairau	Hydro, run of river	73
2012	Hawea Control Gate Retrofit	Hydro, peaking	17
	Te Waka	Wind	102
2014	Generic OCGT NI 3	Peaker, diesel-fired OCGT	150
2015	Demand-side response 1 NI	Price-responsive load curtailment	100
2016	Demand-side response 1 SI	Price-responsive load curtailment	50
2017	Tauhara stage 2	Geothermal	200
2018	Tauhara stage 1	Geothermal	20
	Mokai 4	Geothermal	40
	New IL 1	Interruptible load	50
2019	Kawerau stage 2	Geothermal	67
	Clutha River Luggate	Hydro, peaking	100
2020	Generic OCGT NI 2	Peaker, diesel-fired OCGT	150
	Rotokawa 3	Geothermal	67
	Demand-side response 2 SI	Price-responsive load curtailment	50
	Demand-side response 2 NI	Price-responsive load curtailment	50
2021	Ngatamariki	Geothermal	67
	New IL 2	Interruptible load	50
2022	Marsden Coal	Coal	320
2024	Marsden Point Refinery	Co-generation, gas-fired	85
2025	Coal seam gas plant	Co-generation, other	50
	Demand-side response 3 NI	Price-responsive load curtailment	100

Year	Plant description	Technology description	MW
2026	Huntly coal unit 1	Coal	-226
	Generic lignite 1 Southland	Lignite	400
	Motorimu	Wind	80
2028	Generic coal 1 Glenbrook	Coal	400
	Huntly coal unit 2	Coal	-226
2029	Generic coal 4 Tauranga	Coal	300
2030	Huntly coal unit 3	Coal	-226
	Generic lignite 2 Otago	Lignite	400
	Glenbrook upgrade	Co-generation, other	80
2031	Huntly gas	Open cycle gas turbine – gas	-66
	Vehicle-to-grid at peak time 1	Price-responsive load curtailment	100
	Demand-side response 3 SI	Price-responsive load curtailment	50
	Demand-side response 4 NI	Price-responsive load curtailment	50
2032	Huntly coal unit 4	Coal	-226
	Otahuhu C	Combined cycle gas turbine	407
2033	Taranaki CC	Combined cycle gas turbine	-360
	Generic geo 1	Geothermal	75
	Long Gully	Wind	70
	Generic wind Wairarapa 1	Wind	100
	Turitea	Wind	150
	Vehicle-to-grid at peak time 2	Price-responsive load curtailment	200
	New IL 3	Interruptible load	50
2034	Generic geo 2	Geothermal	110
2035	Generic geo 3	Geothermal	110
	Wainui Hills	Wind	30
2036	Vehicle-to-grid at peak time 3	Price-responsive load curtailment	300
	Demand-side response 5 NI	Price-responsive load curtailment	50
2037	Puketiro	Wind	120
2038	Generic coal 5 Huntly stage 1	Coal	400
	Otahuhu B	Combined cycle gas turbine	-365
	Generic gas 1 Auckland	Combined cycle gas turbine	410
2039	Lake Mahinerangi	Wind	200

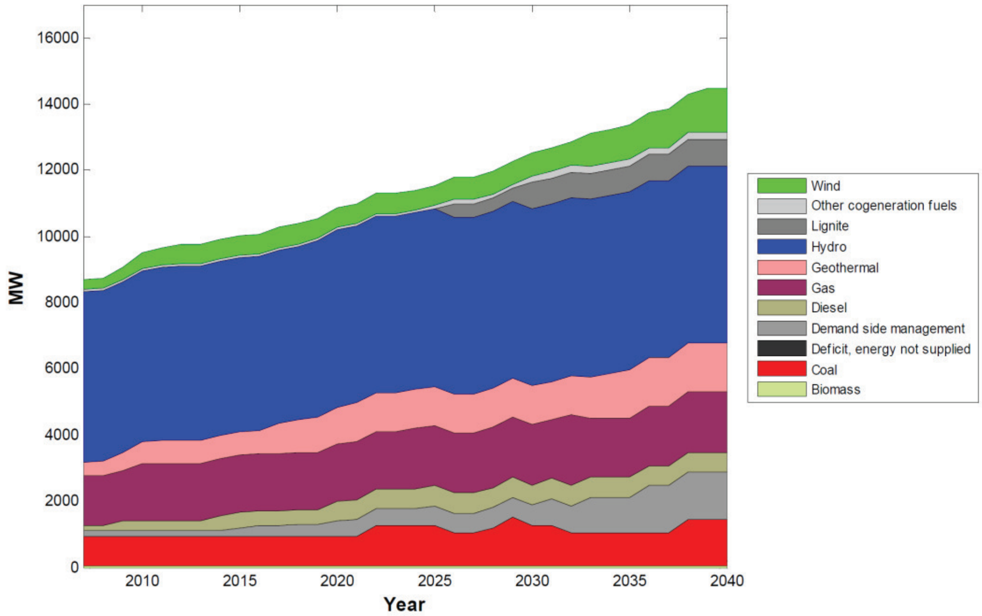


Figure A9: Capacity stackplot by fuel and by year for MDS4 (Demand Side Participation) scenario

Table A5: Build schedules for High Gas Recovery (MDS5)

Year	Plant description	Technology description	MW
2008	Deep Stream	Hydro, run of river	6
2009	Ngawha 2	Geothermal	15
	Kawerau stage 1	Geothermal	90
	West Wind	Wind	143
2010	Gas fired OCGT 1	Peaker, fast start gas-fired peaker	200
2011	Wairakei	Geothermal	-163
	Rotokawa 2	Geothermal	130
	Te Mihi	Geothermal	220
	Te Rere Hau	Wind	49
2012	Tauhara stage 1	Geothermal	20
2013	Generic OCGT NI 5	Peaker, diesel-fired OCGT	150
	Wairau	Hydro, run of river	73
2014	Generic OCGT NI 1	Peaker, diesel-fired OCGT	150
2015	Huntly coal unit 1	Coal	-226
	Huntly coal unit 2	Coal	-226
	Rodney CCGT stage 1	Combined cycle gas turbine	240
	Rodney CCGT stage 2	Combined cycle gas turbine	240
	Taranaki Cogen	Co-generation, gas-fired	50
	Generic OCGT NI 2	Peaker, diesel-fired OCGT	150
2016	Mokai 4	Geothermal	40
2017	Mangawhero to Wanganui Div	Hydro, run of river	60
	New IL 1	Interruptible load	50
2018	Clutha River Queensberry	Hydro, peaking	180
2019	Tauhara stage 2	Geothermal	200
2021	Clutha River Luggate	Hydro, peaking	100
	Demand-side response 2 SI	Price-responsive load curtailment	50
2022	Taranaki CC	Combined cycle gas turbine	-360
	TCC – in limited operation	Combined cycle gas turbine	360
	New IL 2	Interruptible load	50
2023	Otahuhu C	Combined cycle gas turbine	407
2025	Coal seam gas plant	Co-generation, other	50
2026	Kawerau stage 2	Geothermal	67

Year	Plant description	Technology description	MW
2027	Rotokawa 3	Geothermal	67
	New IL 3	Interruptible load	50
2028	Generic OCGT NI 3	Peaker, diesel-fired OCGT	150
2029	Ngatamariki	Geothermal	67
2030	Huntly coal unit 3	Coal	-226
	Marsden Coal	Coal	320
	Glenbrook upgrade	Co-generation, other	80
2031	Huntly gas	Open cycle gas turbine – gas	-66
	Generic OCGT NI 4	Peaker, diesel-fired OCGT	150
	Turitea	Wind	150
	Demand-side response 4 NI	Price-responsive load curtailment	50
2032	Huntly coal unit 4	Coal	-226
	Generic gas 1 Auckland	Combined cycle gas turbine	410
2033	TCC – in limited operation	Combined cycle gas turbine	-360
	Taranaki CC 2	Combined cycle gas turbine	380
	Puketiro	Wind	120
2034	Pouto	Wind	300
2035	Generic coal 3 Christchurch	Coal	400
2036	Generic coal 1 Glenbrook	Coal	400
2038	Otahuhu B	Combined cycle gas turbine	-365
	Generic gas 2 Taranaki	Combined cycle gas turbine	410
2039	Marsden Point Refinery	Co-generation, gas-fired	85

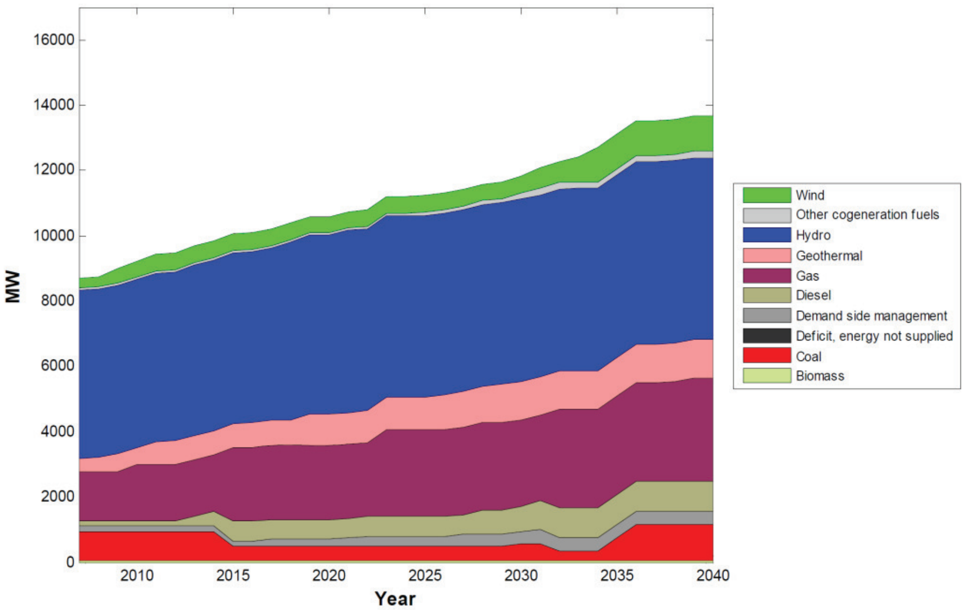


Figure A10: Capacity stackplot by fuel and by year for MDS5 (High Gas Recovery) scenario

C4. Forecasts of key economic drivers used for demand forecasts in SOO2008

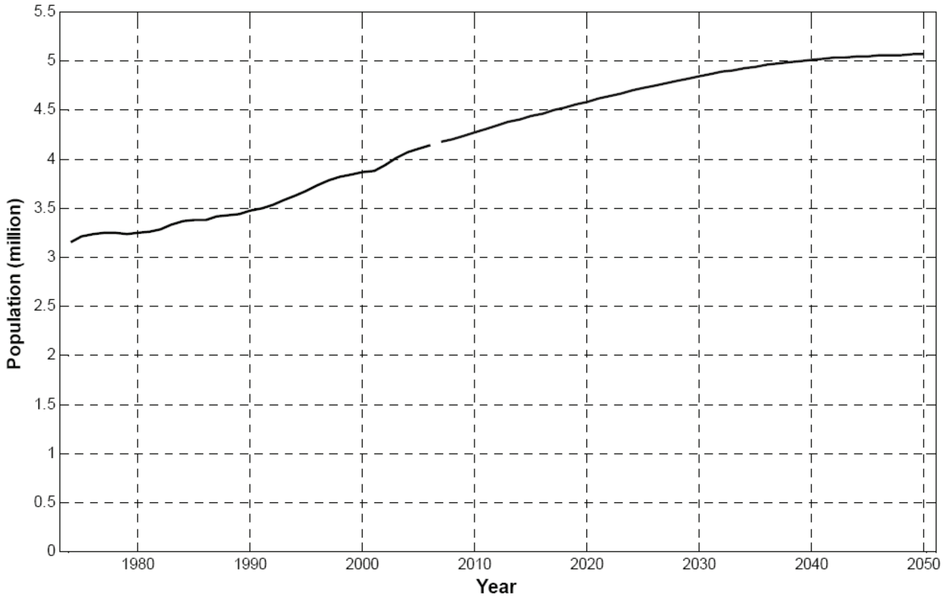


Figure A11: Total New Zealand population – mean forecast

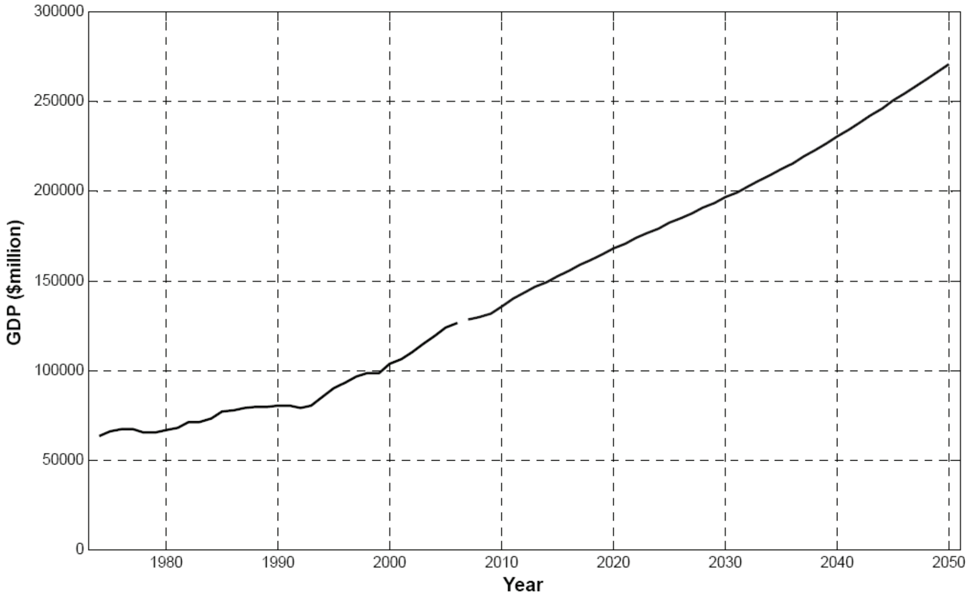


Figure A12: Total New Zealand real GDP ($1995/1996) – mean forecast

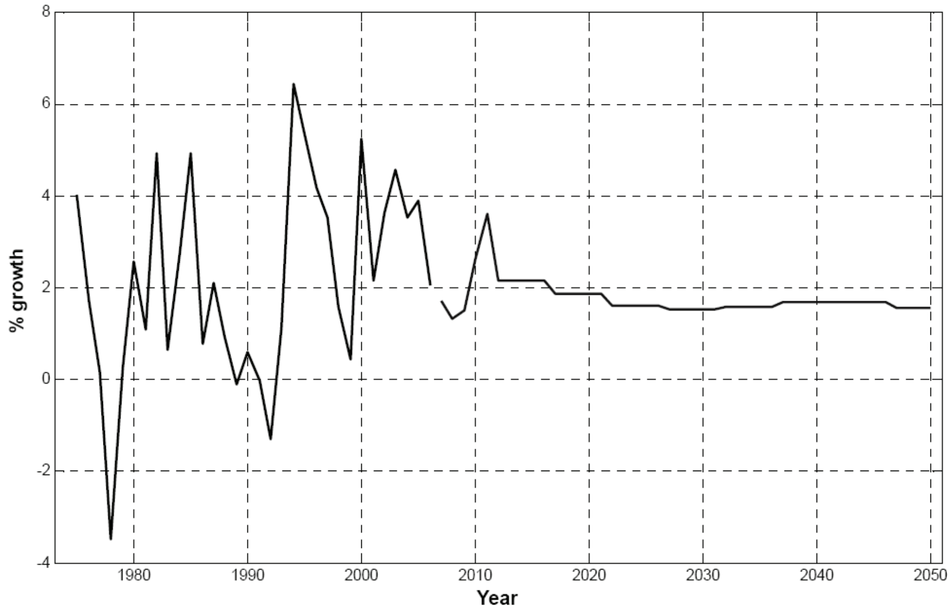


Figure A13: Total New Zealand real GDP ($1995/1996) – percentage growth

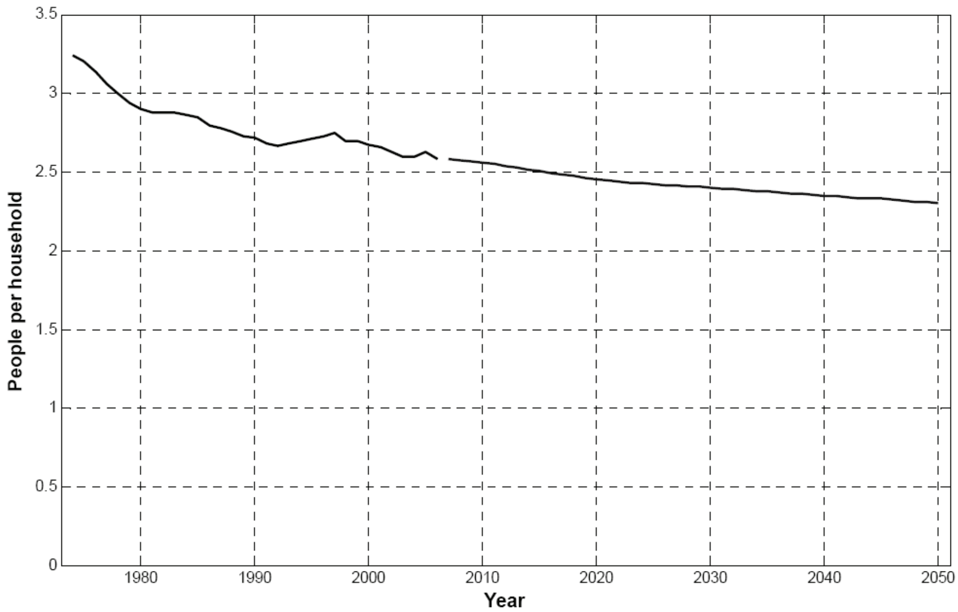


Figure A14: Average New Zealand household size

C5. National energy demand projections – March years (GWh) (Electricity Commission 2008)

Year	Baseline	80 percent confidence limits		Sectoral breakdown			
		High	Low	Residential	Commercial & industrial[52]	Local lines losses	Embedded generation excluded
2007	37,820	38,015	37,564	12,674	25,388	1,702	1,944
2008	38,182	38,645	37,652	12,790	25,634	1,721	1,963
2009	38,616	39,303	37,862	12,936	25,921	1,743	1,985
2010	39,288	40,180	38,346	13,102	26,427	1,778	2,019
2011	40,234	41,326	39,077	13,329	27,146	1,827	2,068
2012	40,882	42,155	39,532	13,532	27,590	1,861	2,101
2013	41,523	42,975	39,971	13,719	28,044	1,894	2,134
2014	42,192	43,806	40,453	13,924	28,508	1,929	2,169
2015	42,884	44,690	40,935	14,141	28,982	1,964	2,204
2016	43,578	45,579	41,420	14,351	29,466	2,000	2,240
2017	44,202	46,401	41,879	14,551	29,890	2,033	2,272
2018	44,839	47,227	42,322	14,754	30,323	2,066	2,305
2019	45,484	48,039	42,783	14,960	30,763	2,099	2,338
2020	46,140	48,861	43,221	15,167	31,212	2,133	2,372
2021	46,798	49,745	43,661	15,367	31,669	2,167	2,405
2022	47,368	50,492	44,067	15,534	32,072	2,197	2,435
2023	47,946	51,265	44,481	15,701	32,482	2,227	2,464
2024	48,530	52,081	44,844	15,869	32,898	2,257	2,494
2025	49,121	52,866	45,190	16,037	33,321	2,287	2,525
2026	49,718	53,673	45,639	16,204	33,751	2,318	2,555
2027	50,295	54,425	45,986	16,368	34,164	2,348	2,585
2028	50,878	55,180	46,353	16,530	34,584	2,378	2,615
2029	51,466	55,995	46,751	16,692	35,011	2,409	2,645
2030	52,059	56,813	47,138	16,852	35,444	2,440	2,676
2031	52,658	57,651	47,556	17,011	35,883	2,471	2,707
2032	53,280	58,568	47,910	17,172	36,344	2,503	2,739
2033	53,907	59,412	48,295	17,330	36,812	2,535	2,771
2034	54,540	60,327	48,706	17,488	37,287	2,568	2,803
2035	55,179	61,230	49,088	17,644	37,770	2,601	2,836
2036	55,823	62,107	49,518	17,798	38,260	2,635	2,869

Figures in GWh
80 percent confidence limits: High = 90th percentile, Low = 10th percentile
Total demand = Residential demand + Commercial/Industrial Demand + Local lines losses – Embedded generation

C6. The peak demand forecasts for New Zealand with 80% confidence interval

Table A6: Peak demand forecasts for all scenarios except MDS3

Year	Low	Medium/ baseline	High
2012	7301	7615	7939
2013	7384	7741	8112
2014	7468	7870	8284
2015	7555	8000	8467
2016	7626	8118	8633
2017	7706	8239	8800
2018	7786	8360	8970
2019	7866	8484	9134
2020	7951	8609	9304
2021	8012	8717	9463
2022	8081	8828	9638
2023	8146	8939	9806
2024	8211	9051	9979
2025	8280	9165	10139
2026	8347	9277	10306
2027	8411	9389	10472
2028	8470	9502	10639
2029	8533	9616	10805
2030	8604	9734	10993
2031	8672	9849	11167
2032	8737	9963	11332
2033	8795	10079	11506
2034	8861	10195	11691
2035	8914	10314	11867
2036	8989	10439	12058
2037	9051	10566	12251
2038	9114	10695	12465
2039	9195	10826	12679
2040	9257	10958	12882
2041	9328	11090	13093
2042	9393	11224	13306
2043	9472	11362	13536
2044	9530	11493	13749
2045	9596	11634	13971
2046	9665	11767	14195
2047	9725	11902	14426
2048	9784	12040	14686
2049	9855	12178	14914

Table A7: Peak demand forecasts for MDS3

Year	Low	Medium/ baseline	High
2012	7301	7615	7939
2013	7384	7741	8112
2014	7468	7870	8284
2015	7555	8000	8467
2016	7626	8118	8633
2017	7706	8239	8800
2018	7786	8360	8970
2019	7866	8484	9134
2020	7951	8609	9304
2021	8012	8717	9463
2022	7981	8728	9538
2023	7946	8739	9606
2024	7911	8751	9679
2025	7880	8765	9739
2026	7847	8777	9806
2027	7811	8789	9872
2028	7870	8902	10039
2029	7933	9016	10205
2030	8004	9134	10393
2031	8072	9249	10567
2032	8137	9363	10732
2033	8195	9479	10906
2034	8261	9595	11091
2035	8314	9714	11267
2036	8389	9839	11458
2037	8451	9966	11651
2038	8514	10095	11865
2039	8595	10226	12079
2040	8657	10358	12282
2041	8728	10490	12493
2042	8793	10624	12706
2043	8872	10762	12936
2044	8930	10893	13149
2045	8996	11034	13371
2046	9065	11167	13595
2047	9125	11302	13826
2048	9184	11440	14086
2049	9255	11578	14314

C7. Key drivers of the generation scenarios

Scenario	Eventual carbon price ($/t CO_2e)	Renewables preference	Availability of gas	Renewables available	Fate of coal-fired Huntly units	Fate of other thermal power stations	Fate of HVDC Pole 1	Demand-side
Sustainable Path	$60 (rising to this level by 2018)	Restriction on baseload thermal continues indefinitely	High price path; no imported Liquified Natural Gas (LNG)	Extensive hydro, wind and geothermal available; biomass and marine available later	Closed by 2020	TCC, Huntly p40 and Southdown decommissioned by 2025	Half pole on standby until replacement in 2012	Baseline participation; high electric vehicles uptake
South Island Surplus	$50	Restriction continues until 2019; coal-fired plant without CCS can never be built	High price path; no imported LNG	Extensive hydro and wind available, especially in lower SI; some restrictions on geothermal development	By 2020, two units out and two in dry-year reserve mode	TCC in reduced operation from 2023	Half pole on standby until replacement in 2012	Baseline participation
Medium Renewables	$30	Restriction continues until 2019; coal-fired plant without CCS can never be built	Moderate price path; imported LNG from 2020	Extensive wind and geothermal, and some hydro available	By 2020, all four units in dry-year reserve mode		Half pole fully available until replacement in 2012	Baseline participation; Tiwai smelter phases out of operation around 2025
Demand-side Participation	$20	Restriction continues until 2019	Moderate price path; imported LNG from 2020	Extensive wind and geothermal available; little new hydro can be consented; some existing hydro must reduce output from 2020	Coal-fired units remain in operation until 2030		Pole 1 removed from service in 2009 and replaced in 2012	Extensive participation; high electric vehicles uptake, with vehicle-to-grid
High Gas Discovery	$40	Restriction continues until 2019, though CCGTs can be built to replace coal in the 2010s	Low price path	Moderate amounts of wind, geothermal and hydro available	Two units replaced by a new CCGT in 2015; the remaining units run until 2030	TCC in reduced operation from 2023 (displaced by more efficient new plant)	Half pole on standby until replacement in 2012	Minimal participation

APPENDIX D: INSTALLED GENERATION CAPACITIES COMPARISONS FOR DIFFERENT MDS

D1. Installed generation capacities comparisons for MDS1

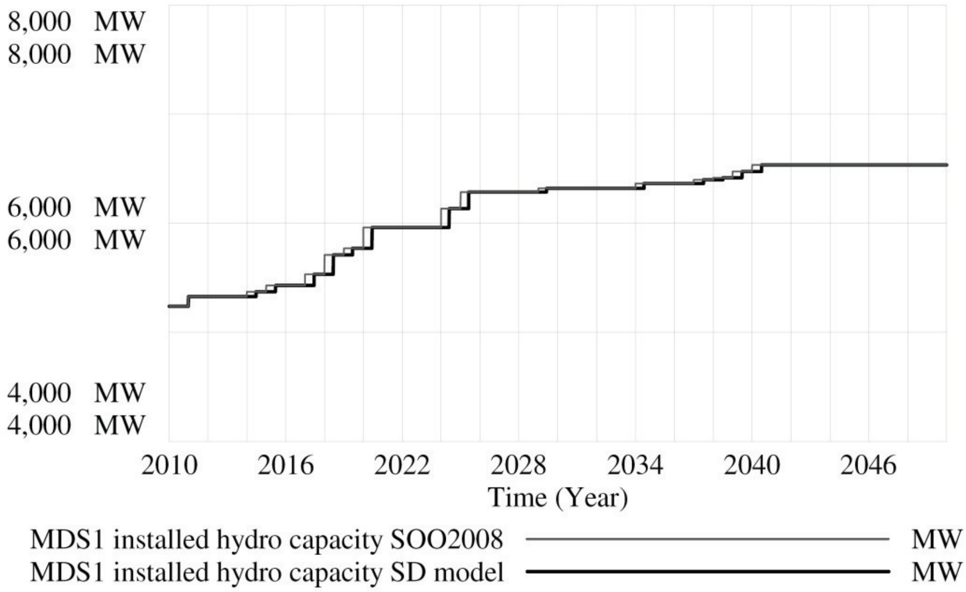


Figure A15: Results comparison for installed hydro capacity for MDS1

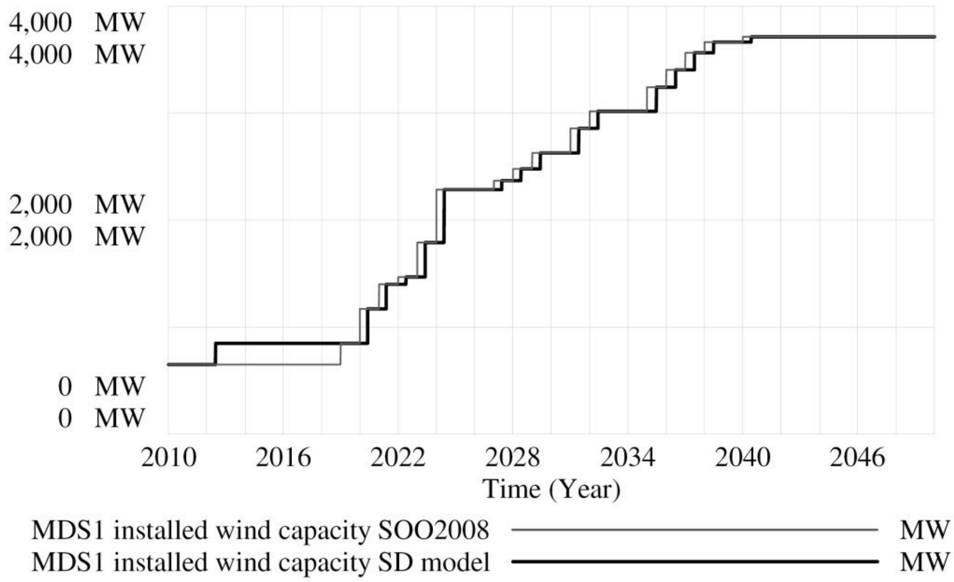


Figure A16: Results comparison for installed wind capacity for MDS1

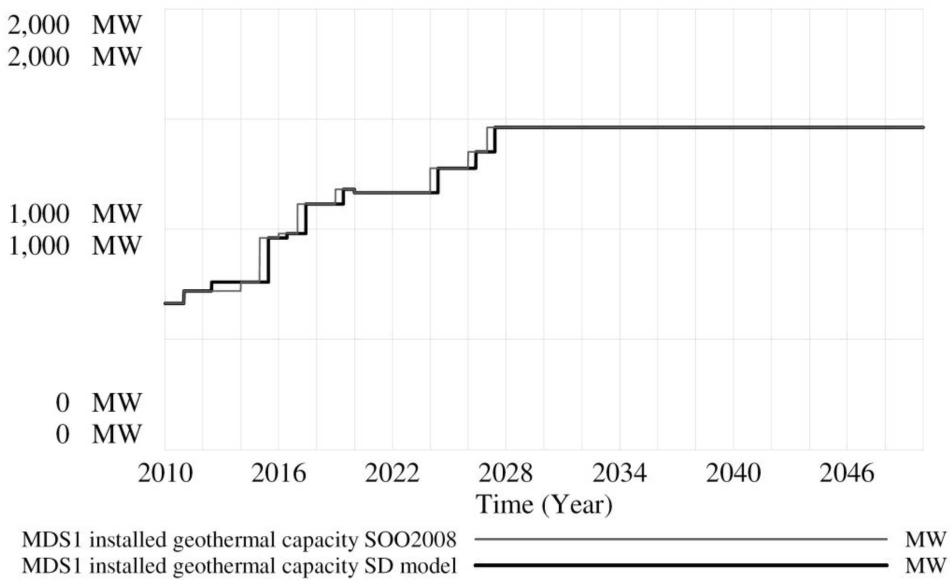


Figure A17: Results comparison for installed geothermal capacity for MDS1

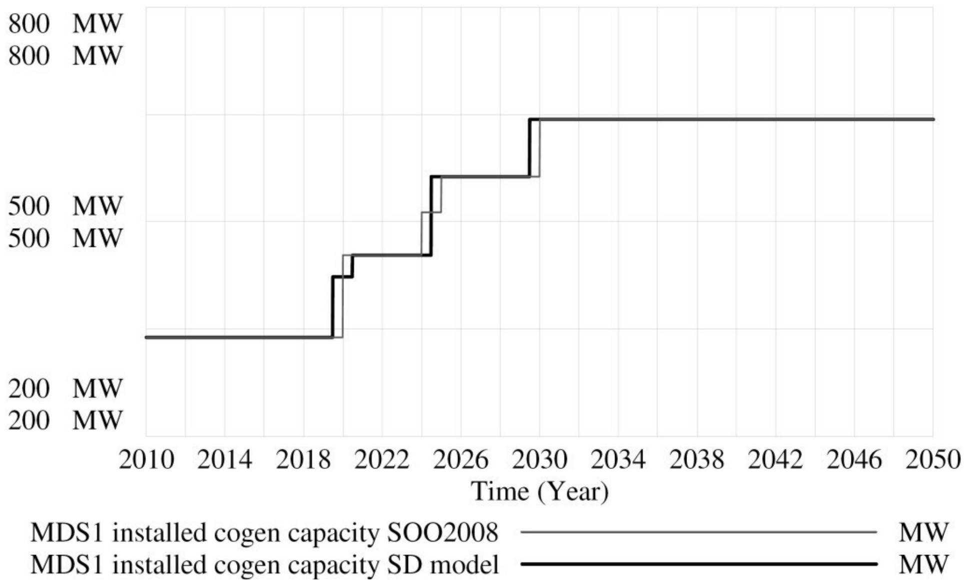


Figure A18: Results comparison for installed cogen capacity for MDS1

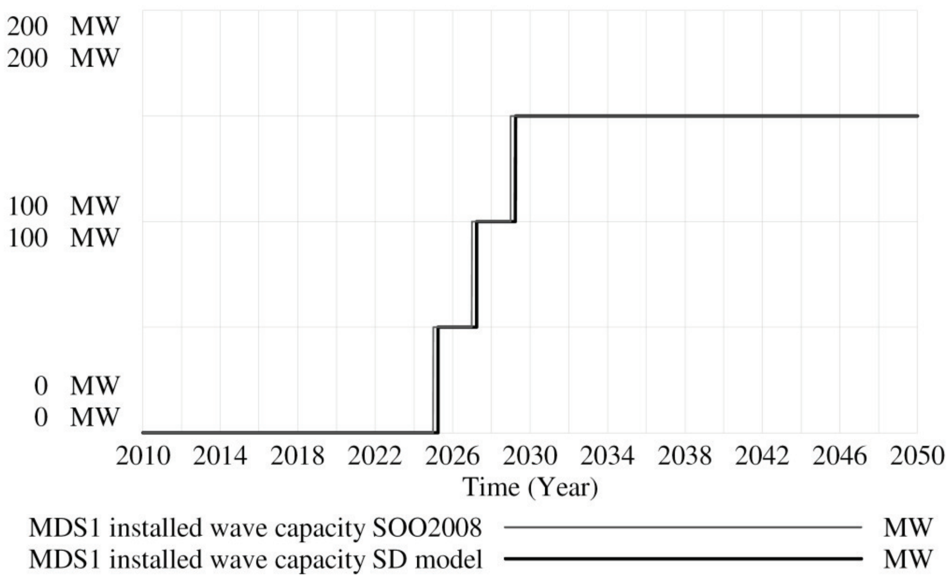


Figure A19: Results comparison for installed wave capacity for MDS1

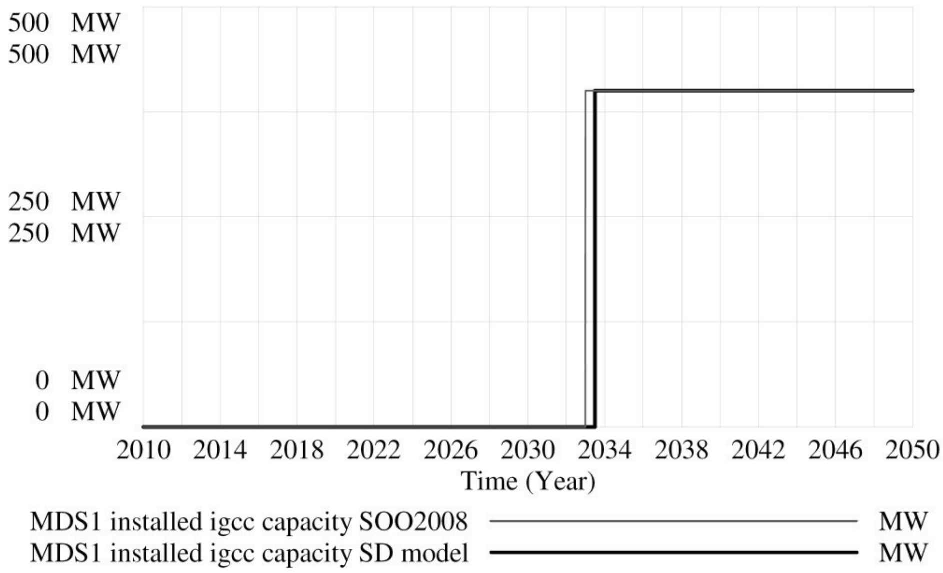


Figure A20: Results comparison for installed IGCC capacity for MDS1

D2. Installed generation capacities comparisons for MDS2

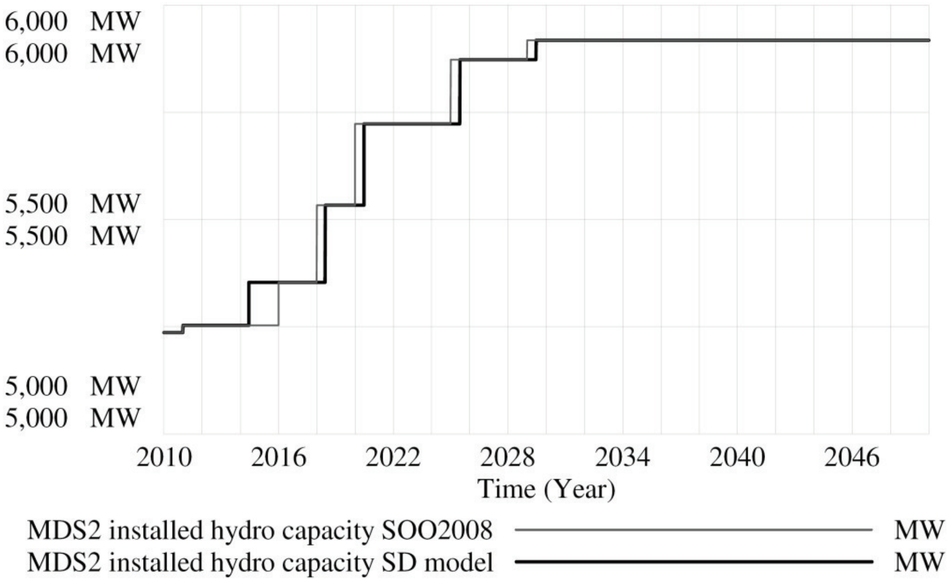


Figure A21: Results comparison for installed hydro capacity for MDS2

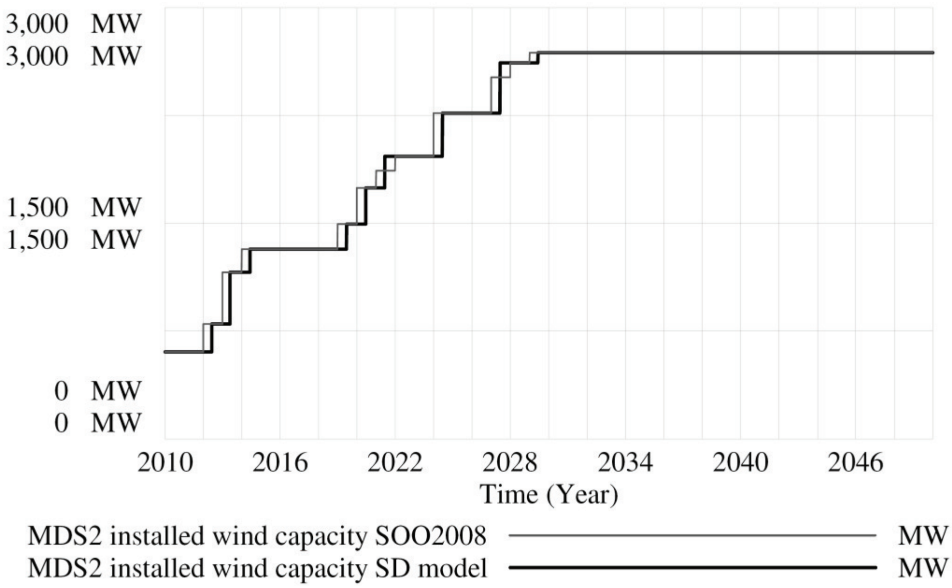


Figure A22: Results comparison for installed wind capacity for MDS2

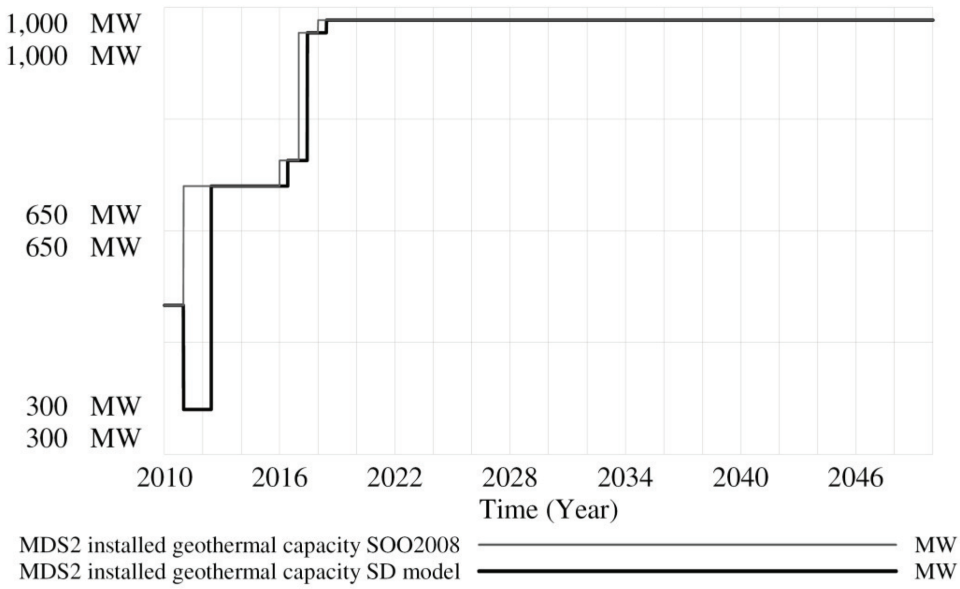


Figure A23: Results comparison for installed geothermal capacity for MDS2

D3. Installed generation capacities comparisons for MDS3

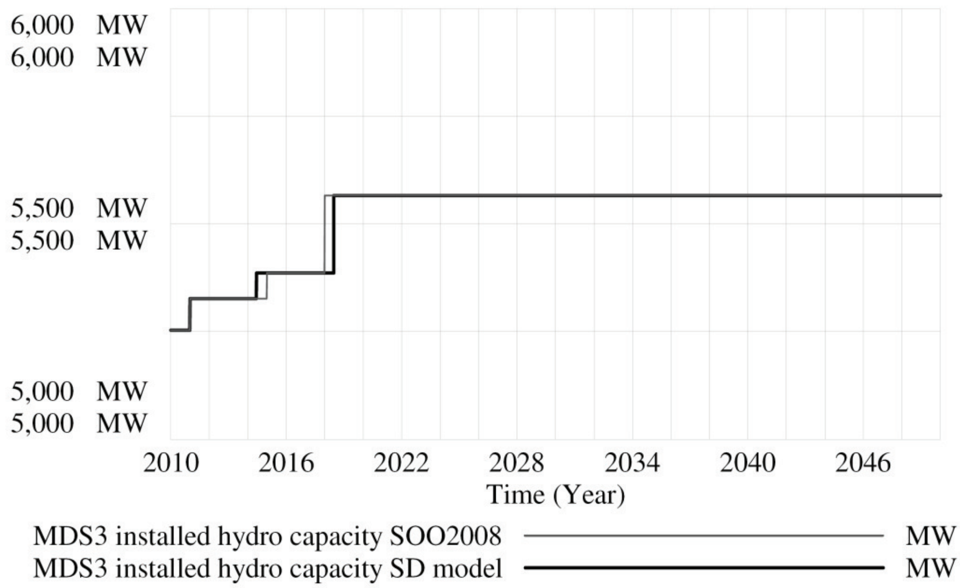


Figure A24: Results comparison for installed hydro capacity for MDS3

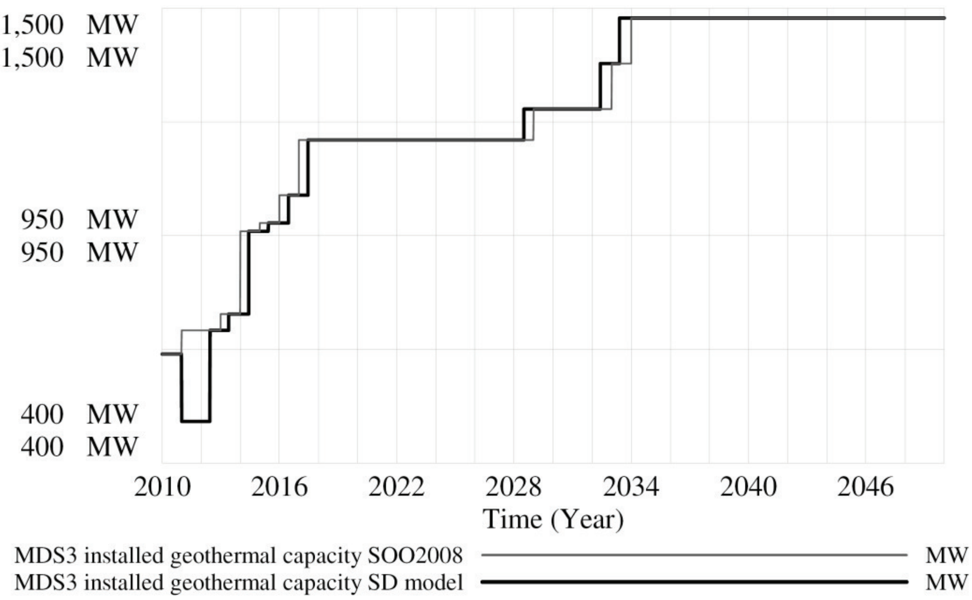


Figure A25:Results comparison for installed geothermal capacity for MDS3

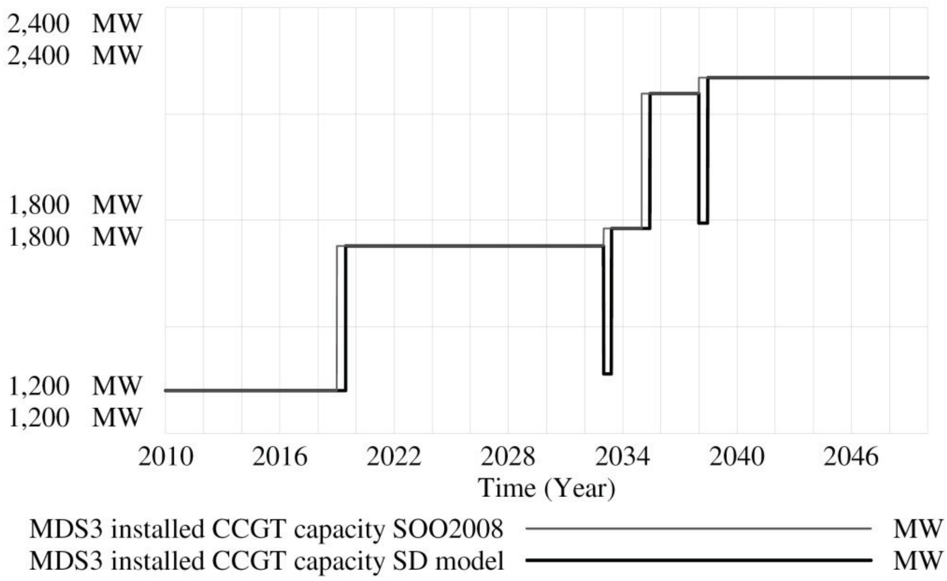


Figure A26: Results comparison for installed CCGT capacity for MDS3

D4. Installed generation capacities comparisons for MDS1

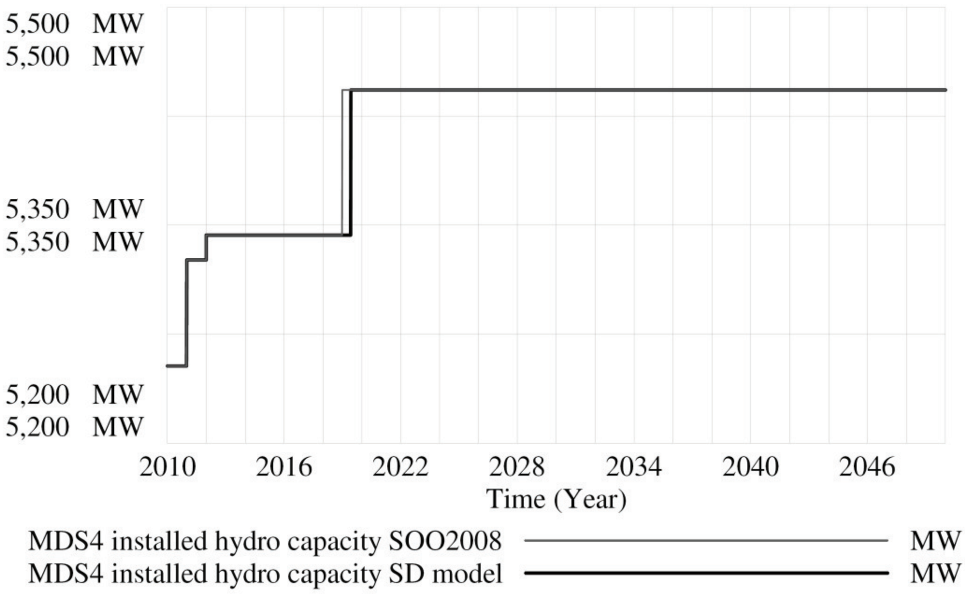


Figure A27: Results comparison for installed hydro capacity for MDS4

D5. Installed generation capacities comparisons for MDS5

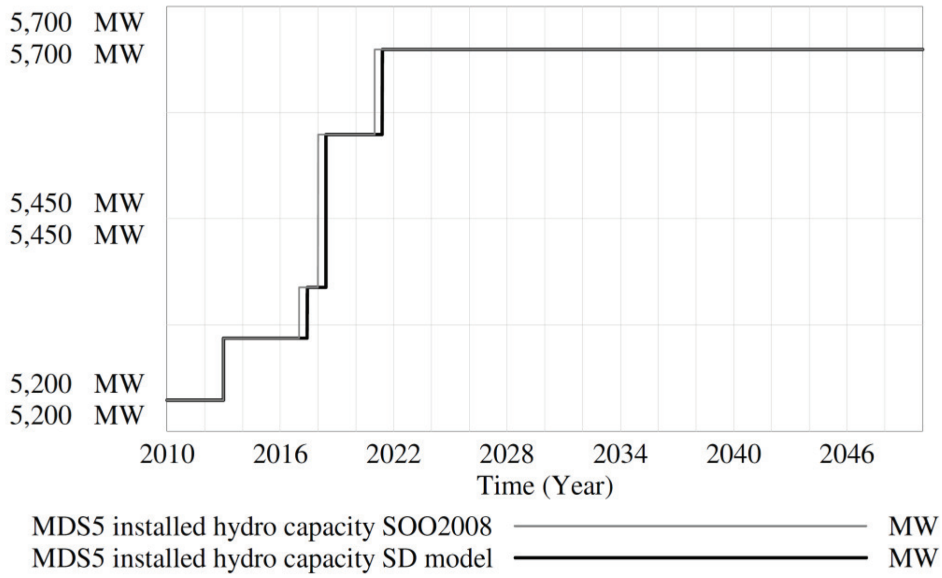


Figure A28: Results comparison for installed hydro capacity for MDS5

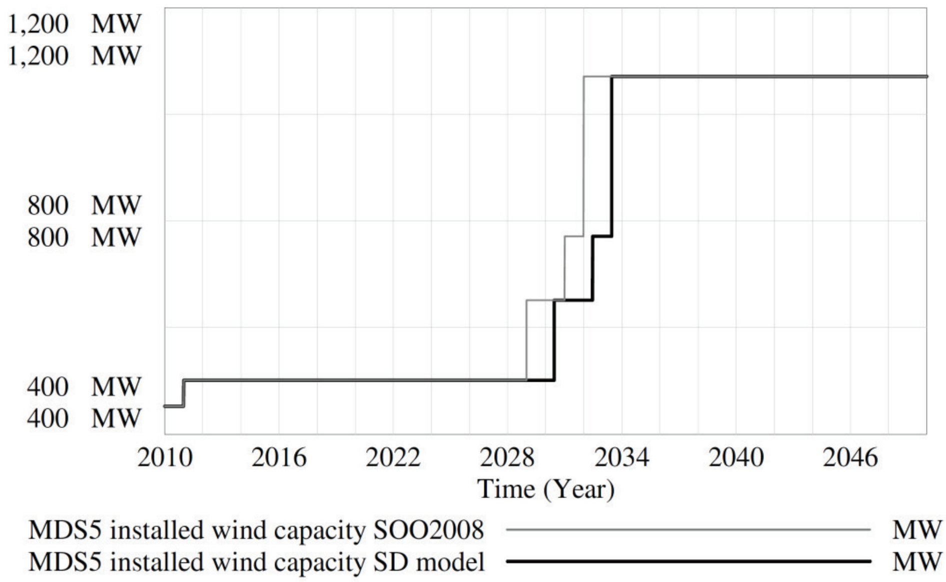


Figure A29: Results comparison for installed wind capacity for MDS5

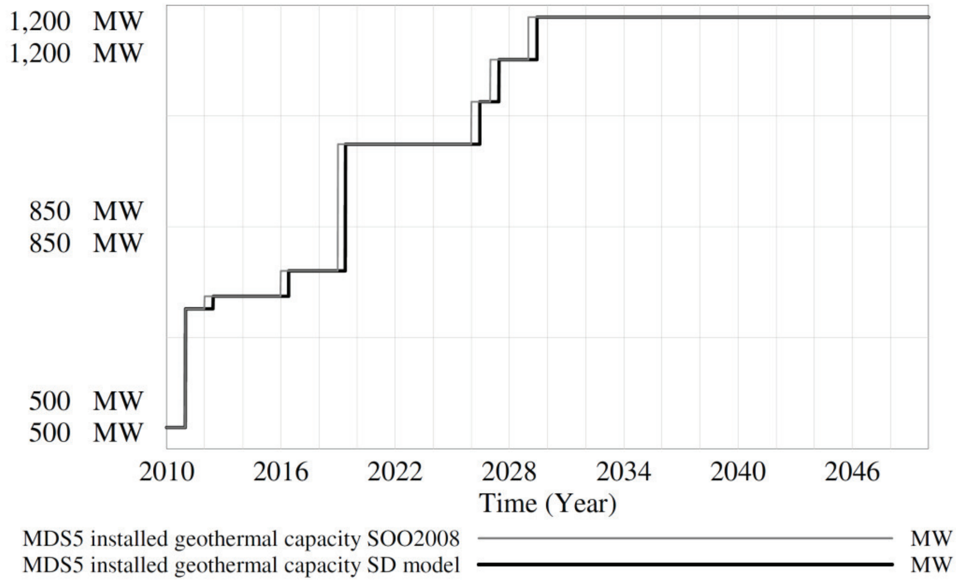


Figure A30: Results comparison for installed geothermal capacity for MDS5

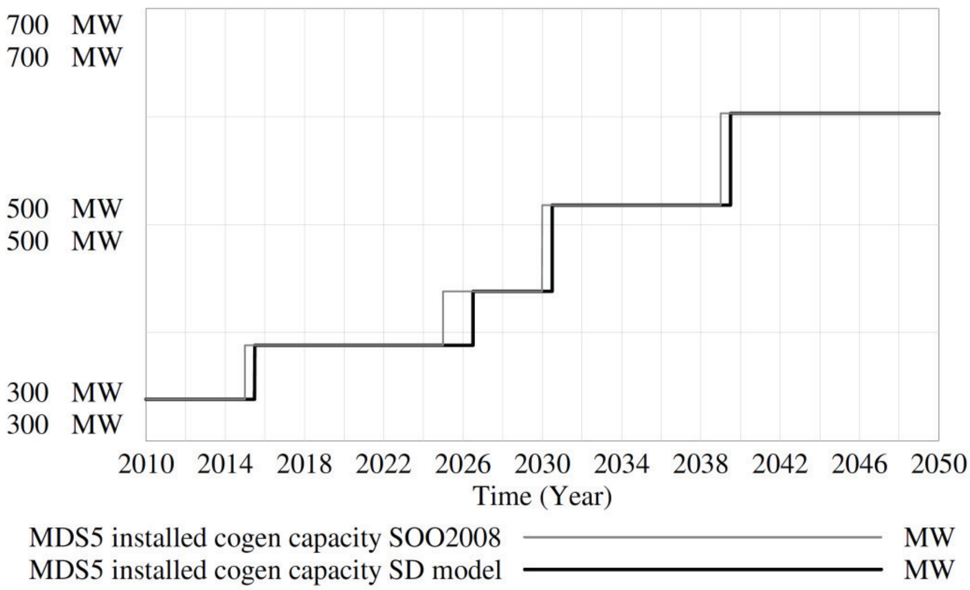


Figure A31: Results comparison for installed cogen capacity for MDS5

Appendix E – Simulation results from the sensitivity analyses

E1.Variations in delays and development duration

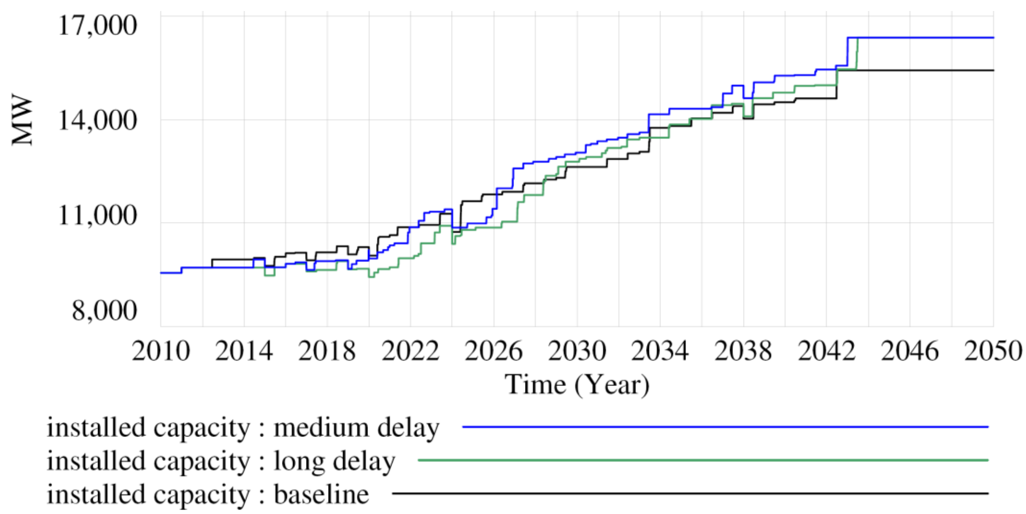


Figure A1: Impacts of delays on the installed capacities for MDS1

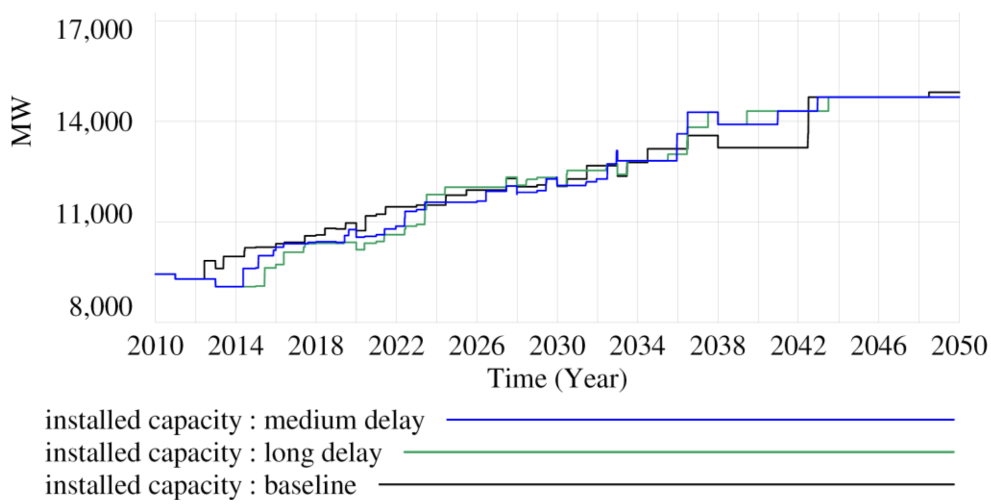


Figure A2: Impacts of delays on the installed capacities for MDS2

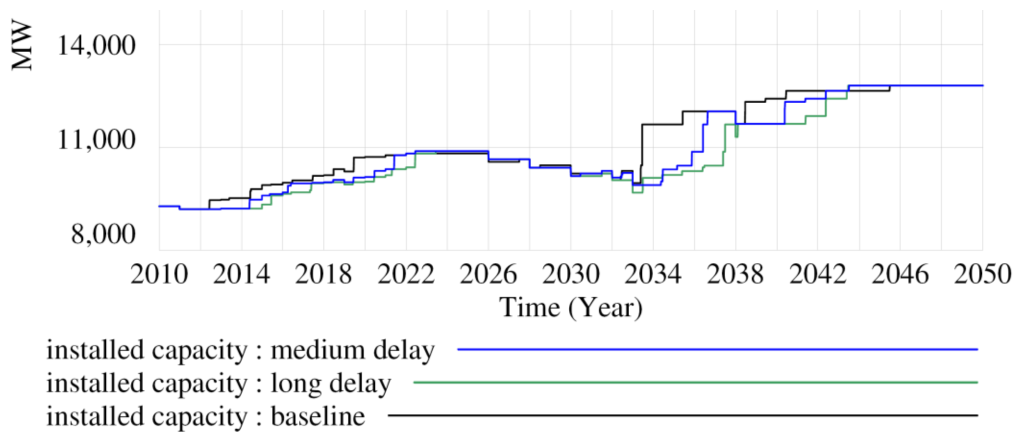


Figure A3: Impacts of delays on the installed capacities for MDS3

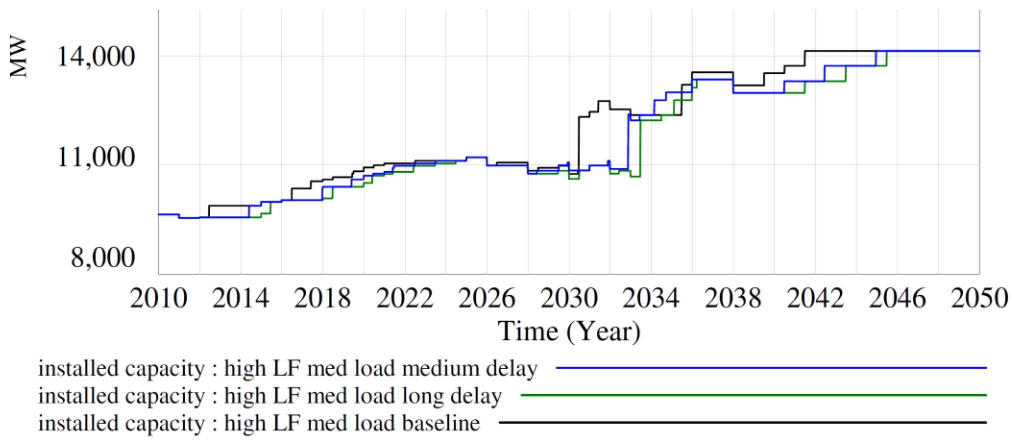


Figure A4: Impacts of delays on the installed capacities for MDS3

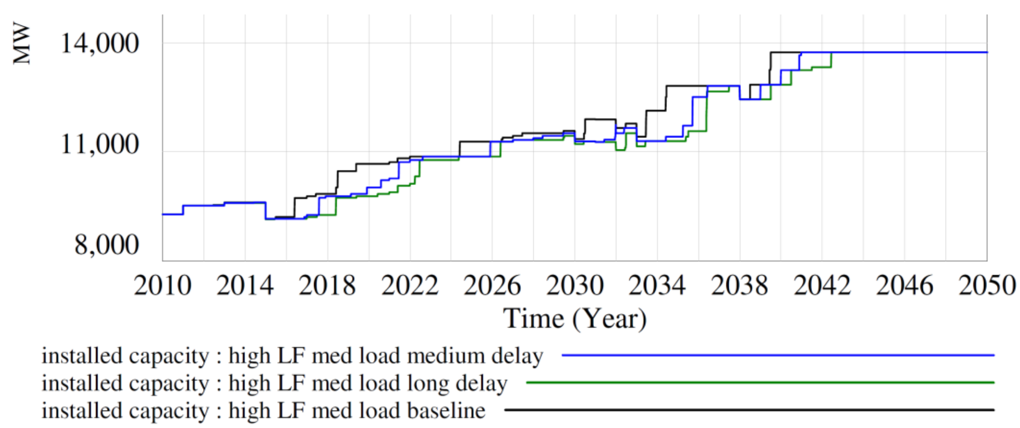


Figure A5: Impacts of delays on the installed capacities for MDS3

E1.2 Impacts of delays on ECM

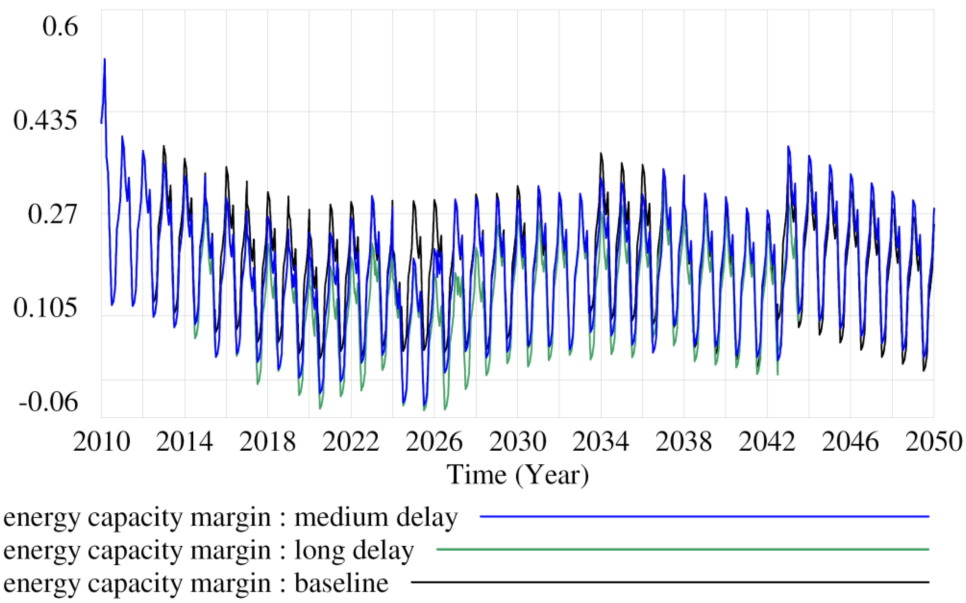


Figure A6: Impacts of delays on ECMs under MDS1

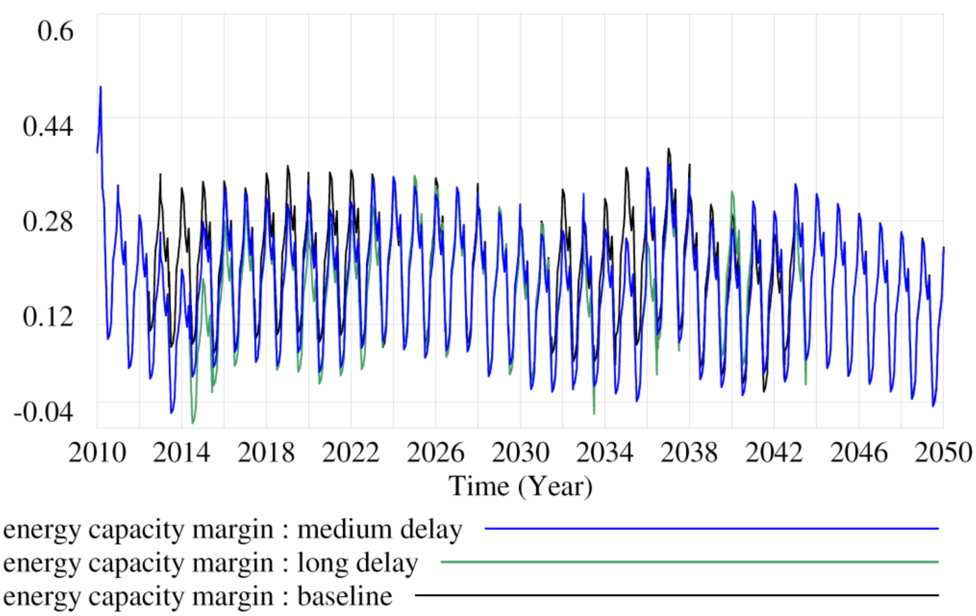


Figure A7: Impacts of delays on ECMs under MDS2

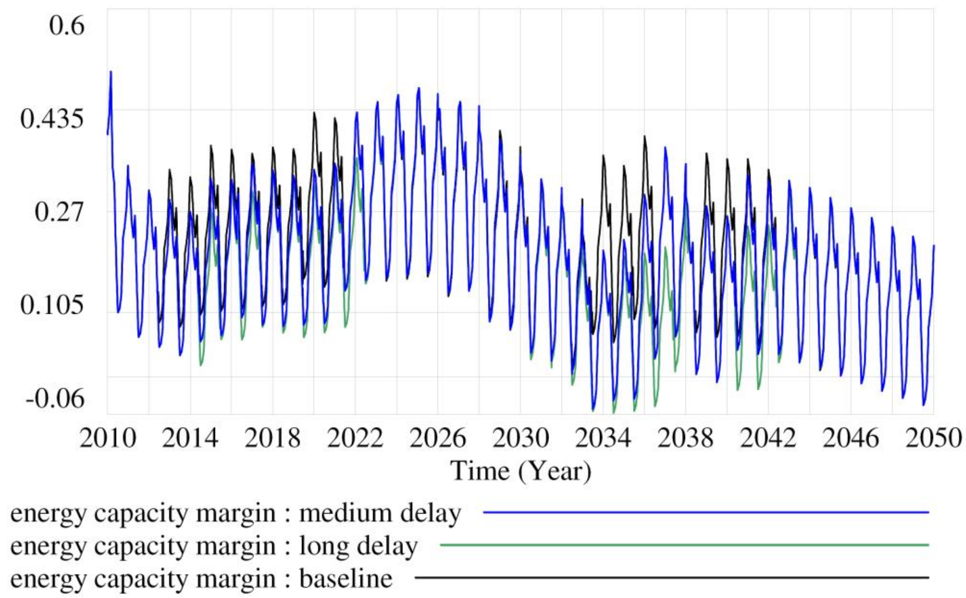


Figure A8: Impacts of delays on ECMs under MDS3

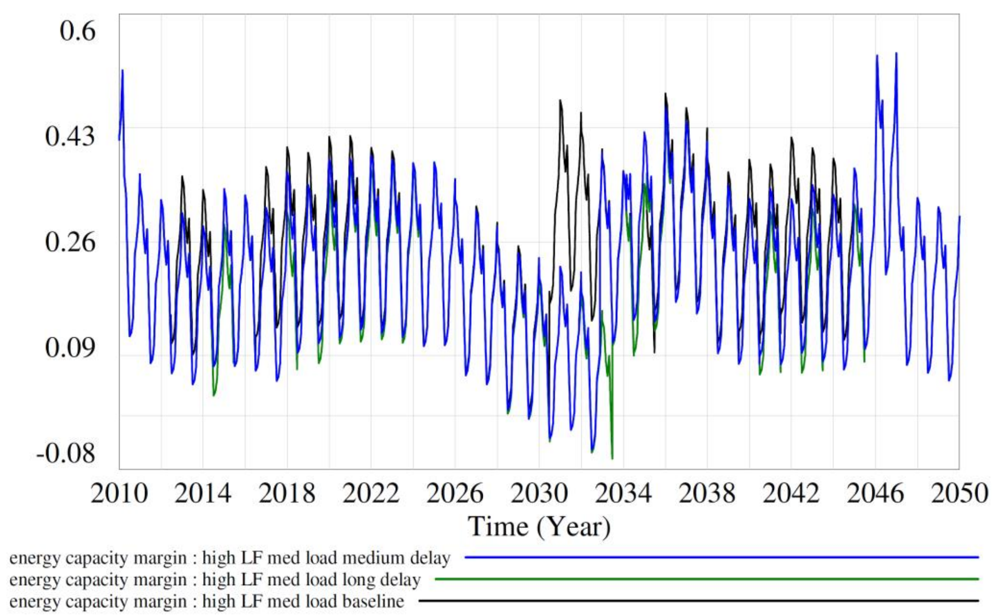


Figure A9: Impacts of delays on ECMs under MDS4

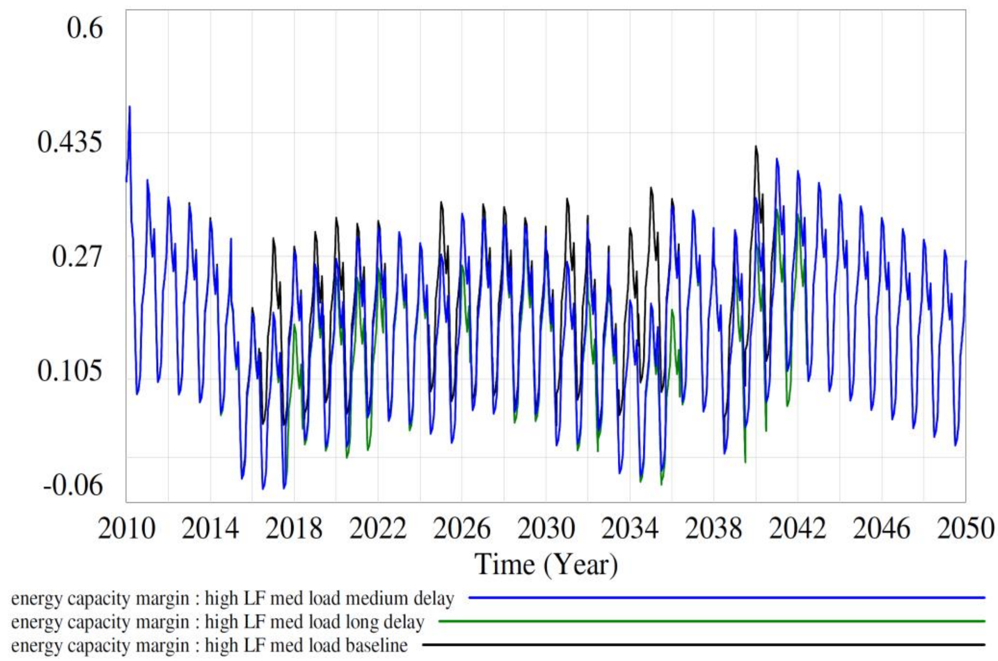


Figure A10: Impacts of delays on ECMs under MDS5

E1.3 Impacts of delays on CM

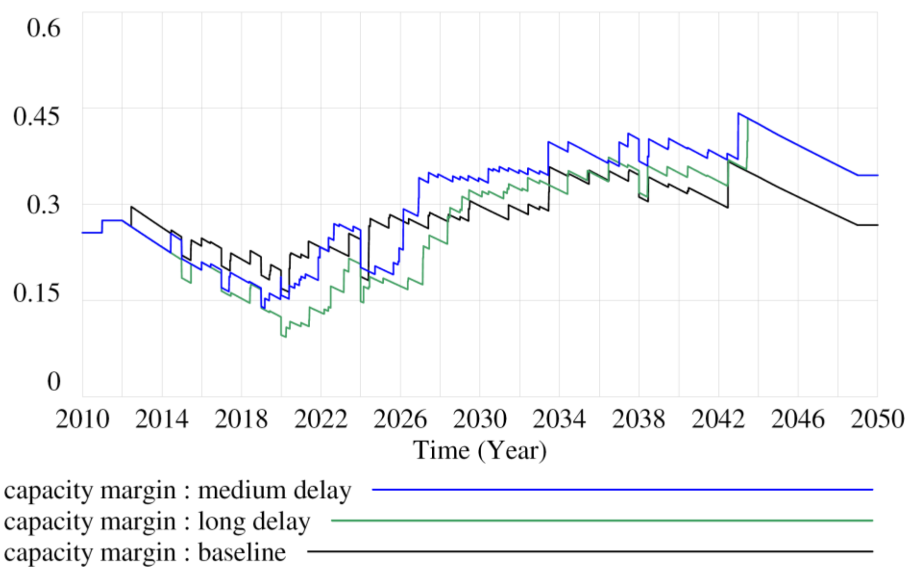


Figure A11: Impacts of delays on CMs under MDS1

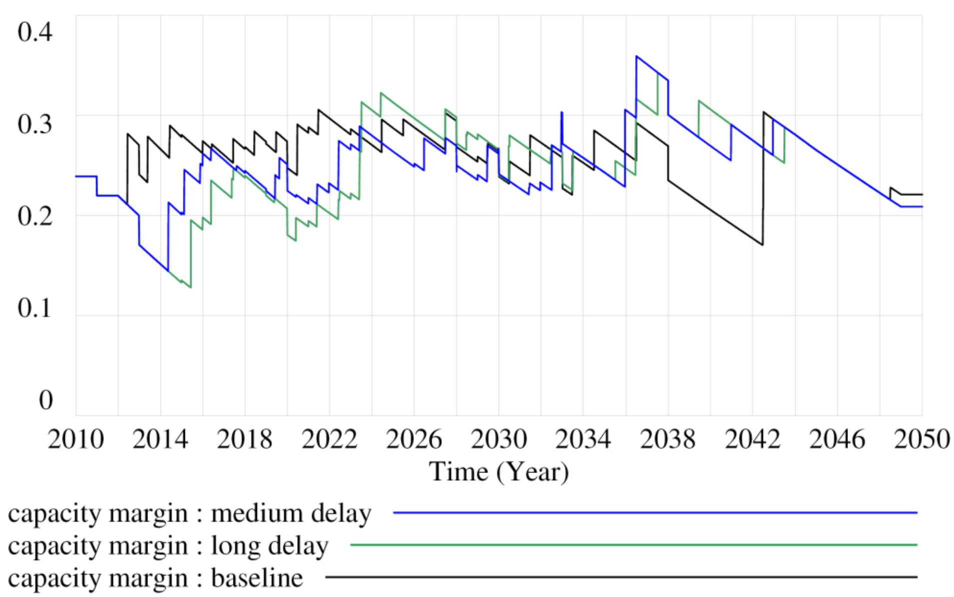


Figure A12: Impacts of delays on CMs under MDS2

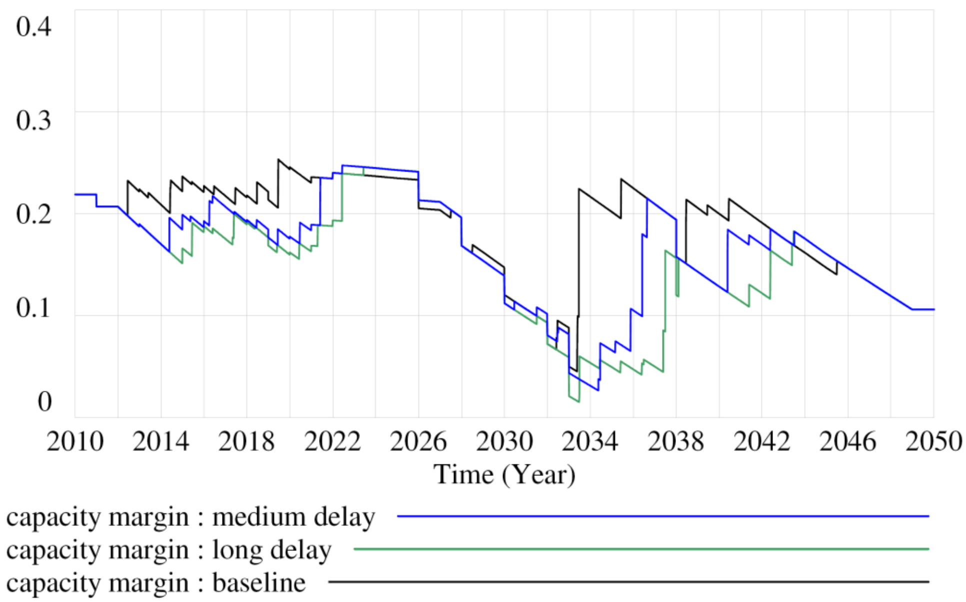


Figure A13: Impacts of delays on CMs under MDS3

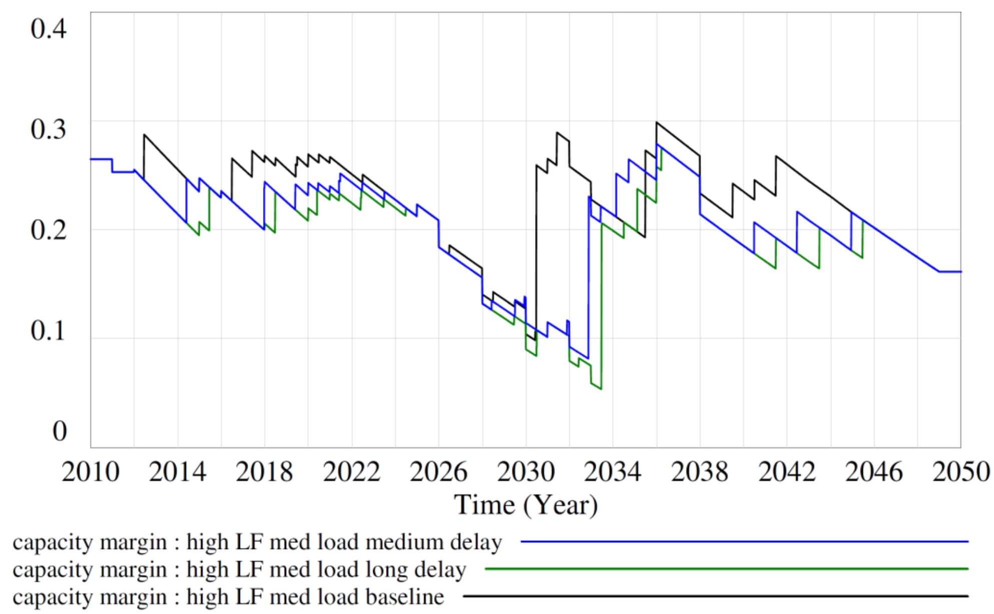


Figure A14: Impacts of delays on CMs under MDS4

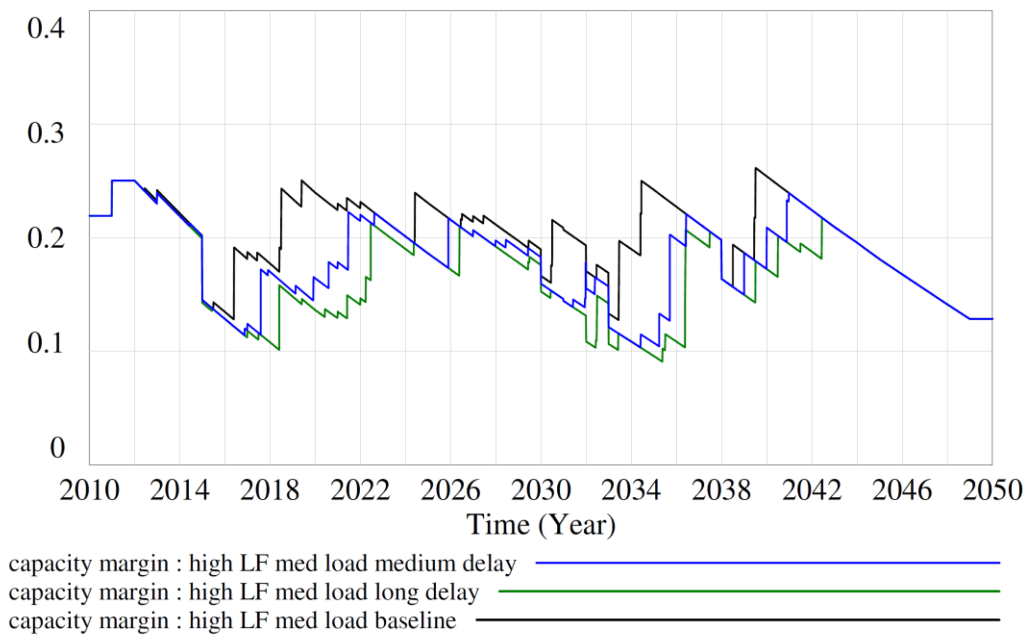


Figure A15: Impacts of delays on CMs under MDS5

E2.Variations in forecasted load

E2.1 Impacts of variations in forecasted load on total installed generation capacities

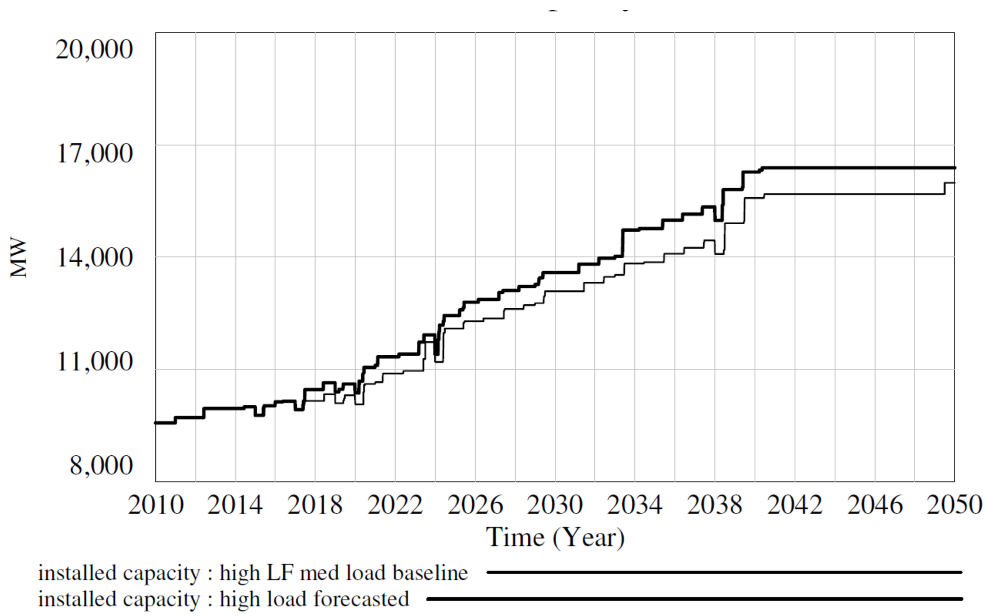


Figure A16: Impacts of load forecast variations on total installed generation capacities under MDS1

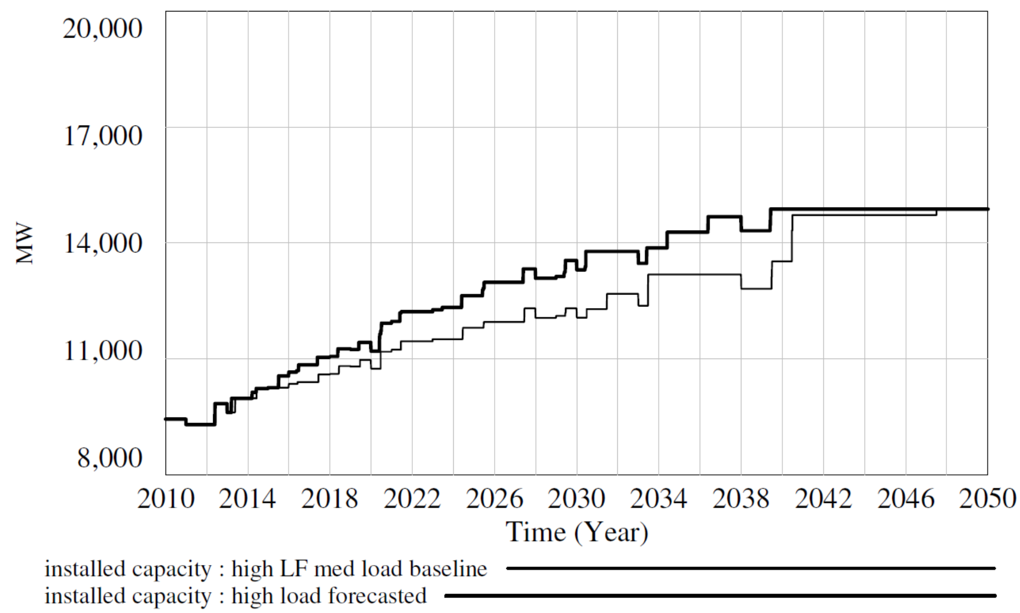


Figure A17: Impacts of load forecast variations on total installed generation capacities under MDS2

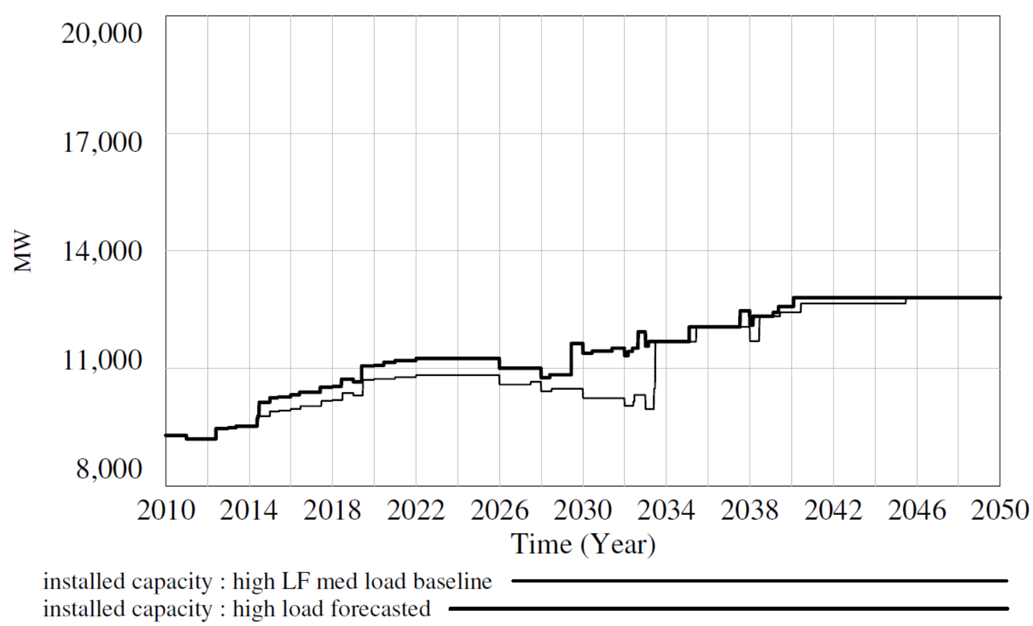


Figure A18: Impacts of load forecast variations on total installed generation capacities under MDS3

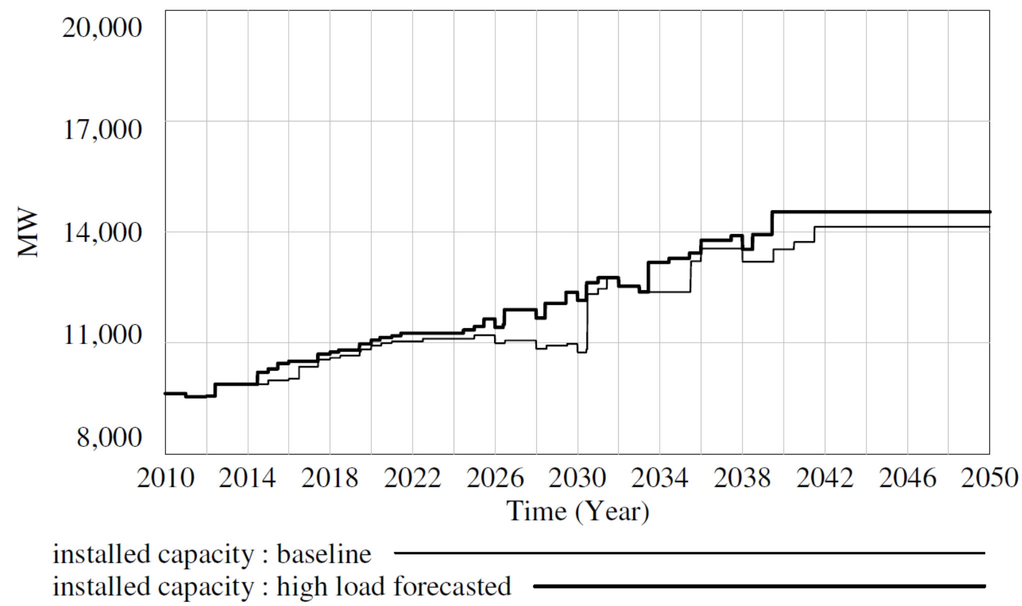


Figure A19: Impacts of load forecast variations on total installed generation capacities under MDS4

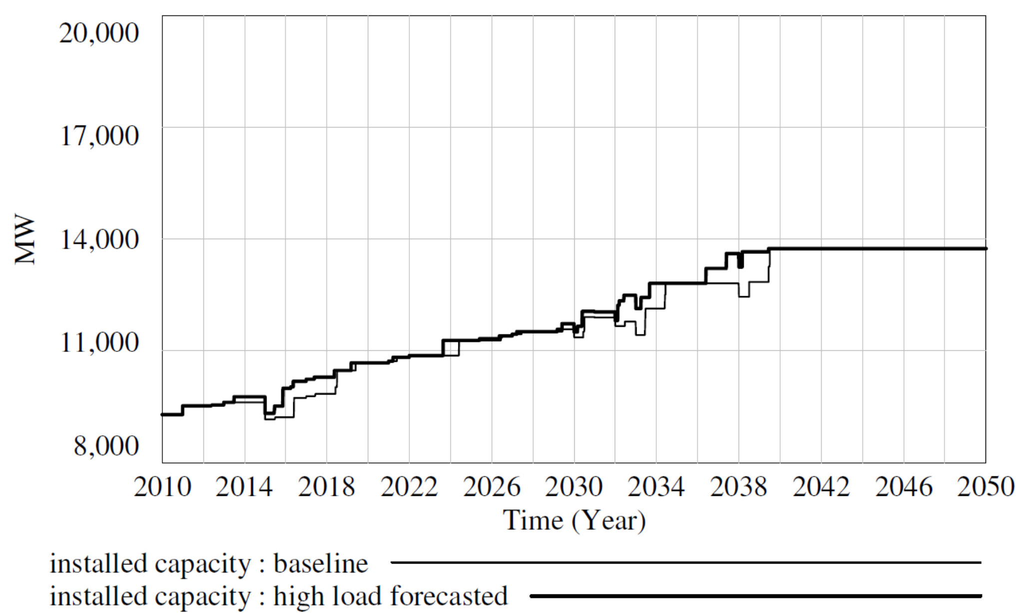


Figure A20: Impacts of load forecast variations on total installed generation capacities under MDS5

E2.2 Impacts of variations in forecasted load on total installed generation capacities

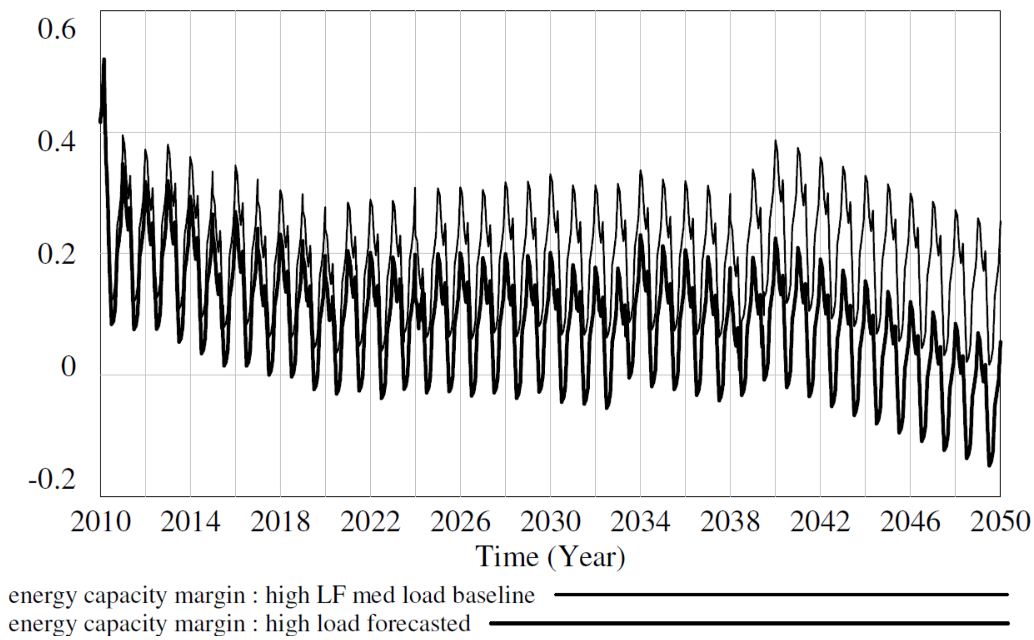


Figure A21: Impacts of load forecast variations on ECMs capacities under MDS1

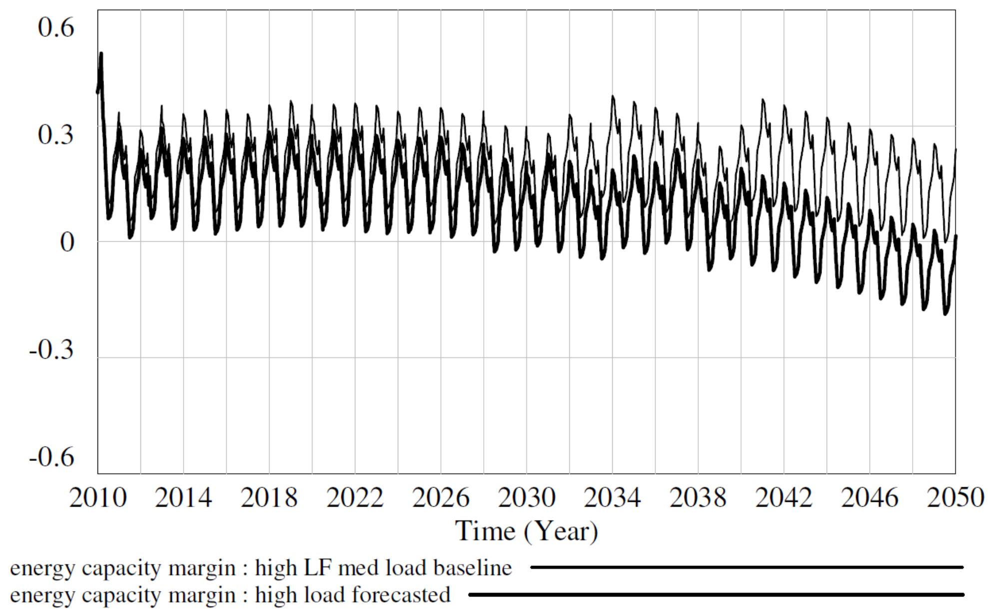


Figure A22: Impacts of load forecast variations on ECMs capacities under MDS2

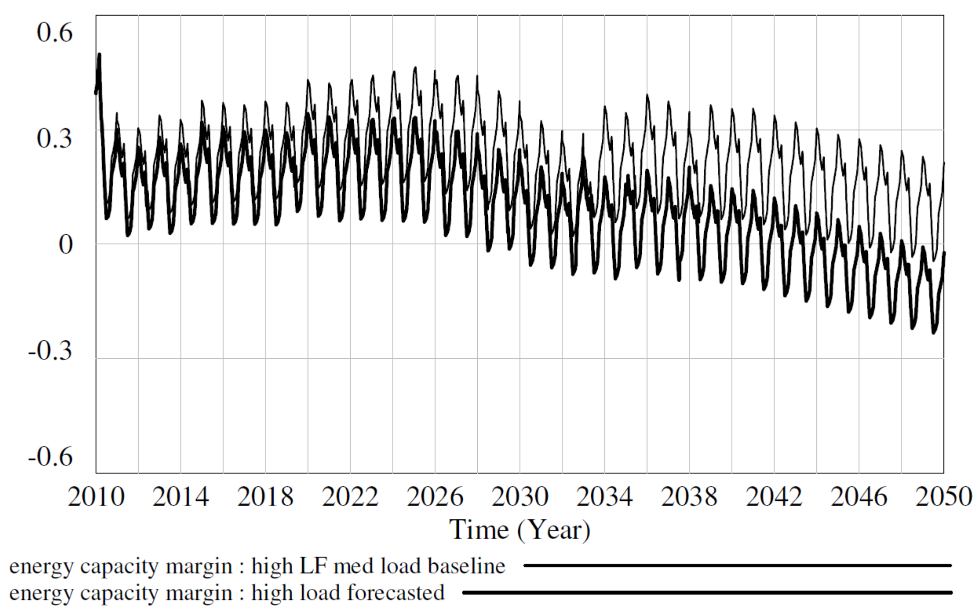


Figure A23: Impacts of load forecast variations on ECMs capacities under MDS3

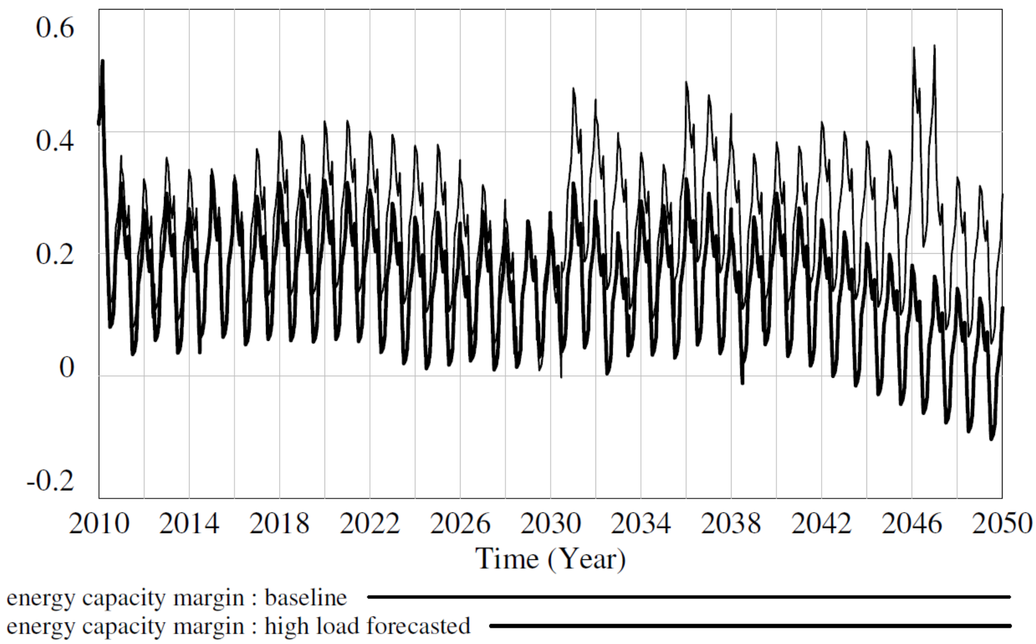


Figure A24: Impacts of load forecast variations on ECMs capacities under MDS4

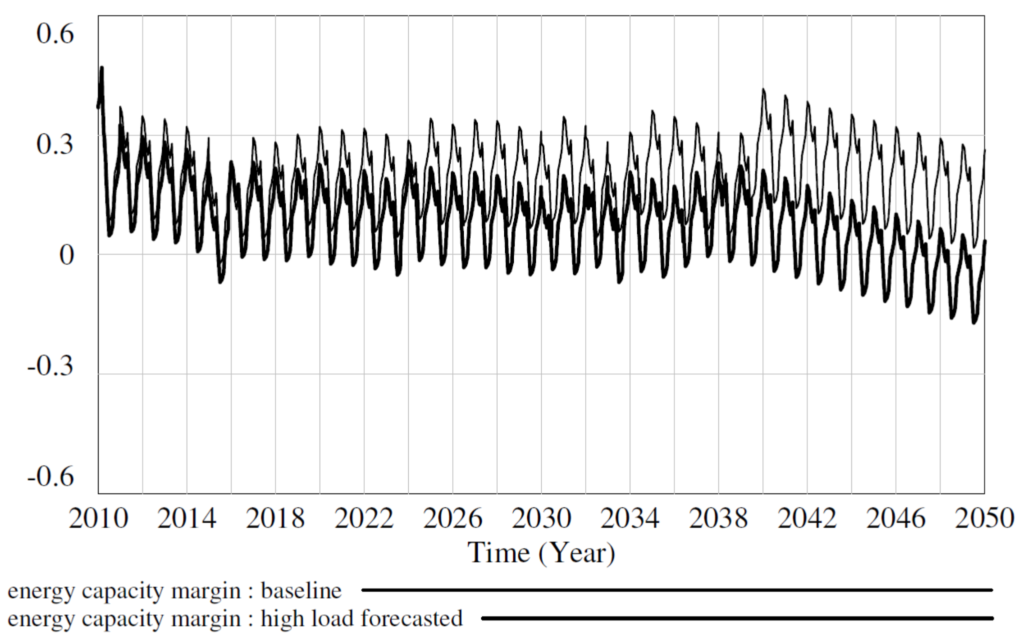
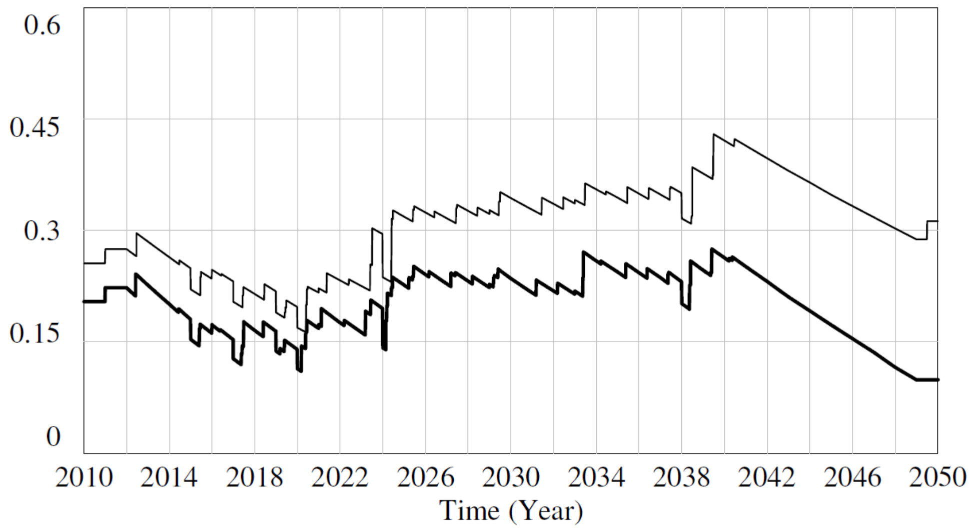


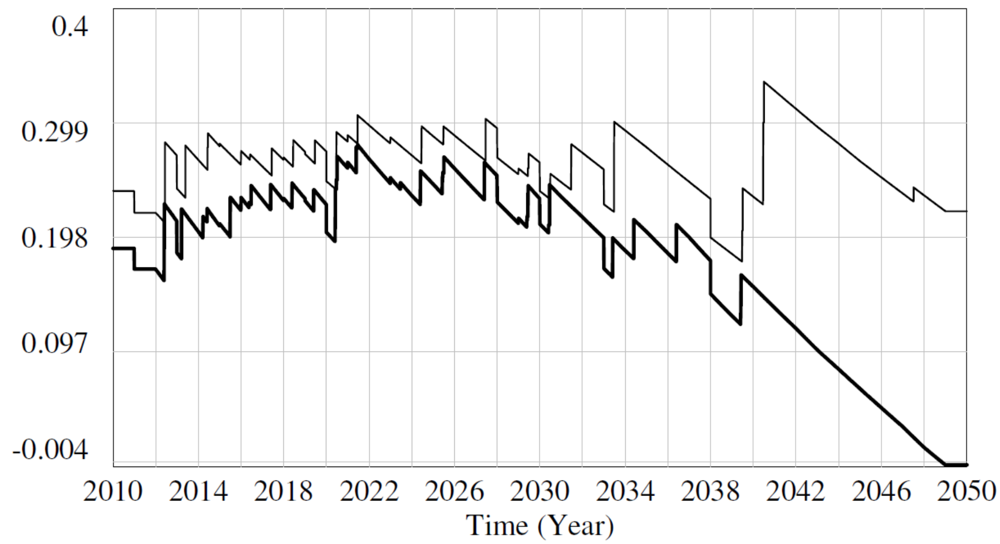
Figure A25: Impacts of load forecast variations on ECMs capacities under MDS5

E2.3 Impacts of variations in forecasted load on total installed generation capacities



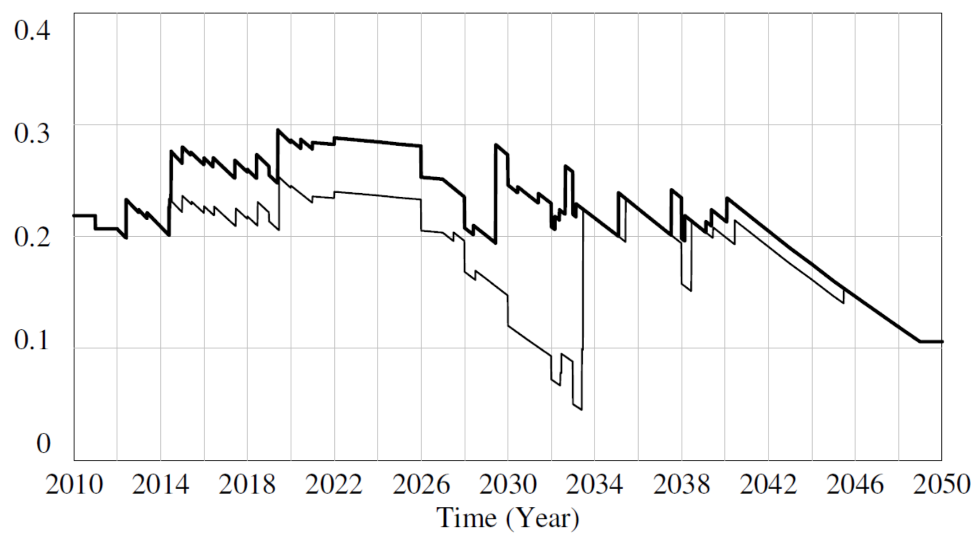
capacity margin : high LF med load baseline
capacity margin : high load forecasted

Figure A26: Impacts of load forecast variations on CMs capacities under MDS1



capacity margin : high LF med load baseline
capacity margin : high load forecasted

Figure A27: Impacts of load forecast variations on CMs capacities under MDS2



capacity margin : high LF med load baseline
capacity margin : high load forecasted

Figure A28: Impacts of load forecast variations on CMs capacities under MDS3

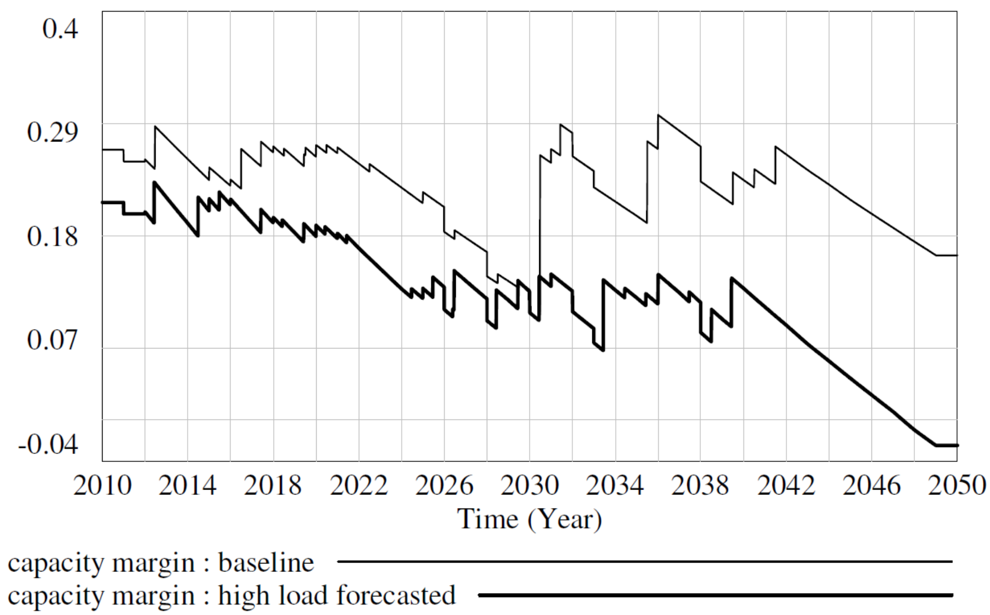


Figure A29: Impacts of load forecast variations on CMs capacities under MDS4

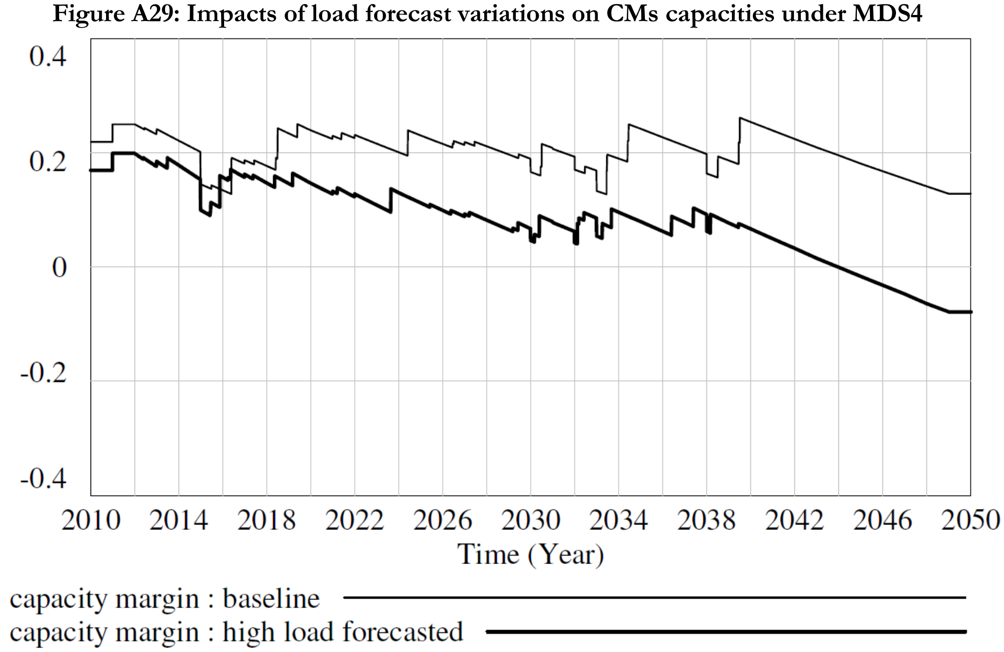


Figure A30: Impacts of load forecast variations on CMs capacities under MDS

Appendix F: Full Vensim SD Model Used in this Study

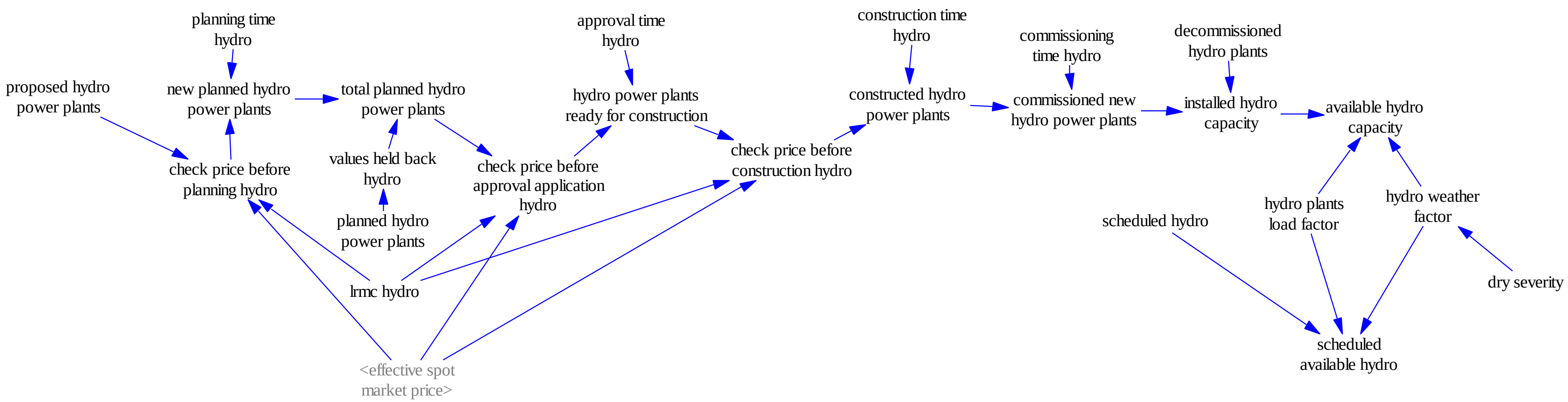


Figure A. 62: Model for hydro plants development

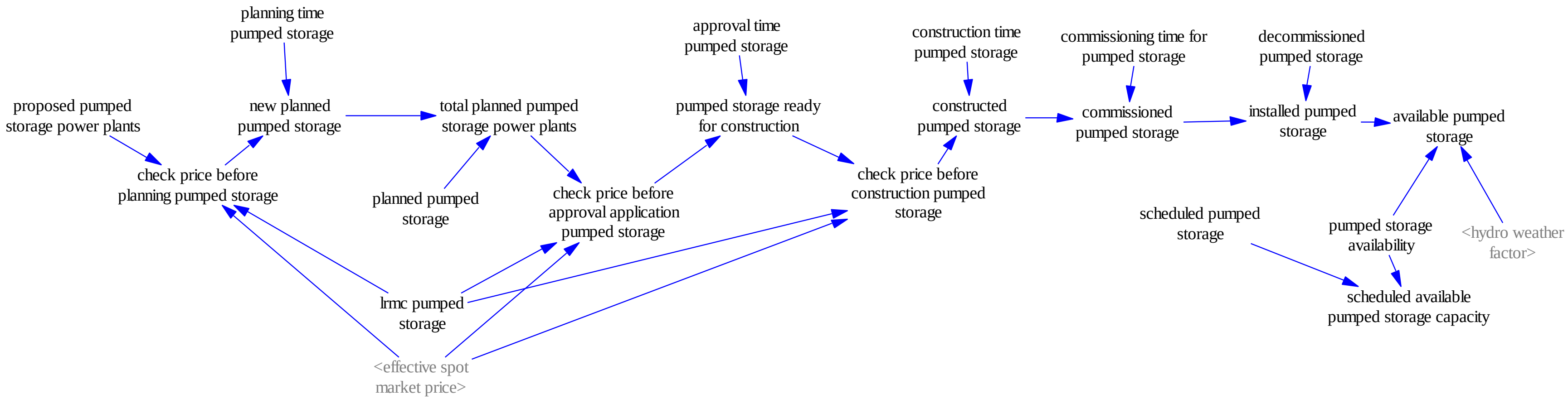


Figure A. 63: Model for pumped storage plants development

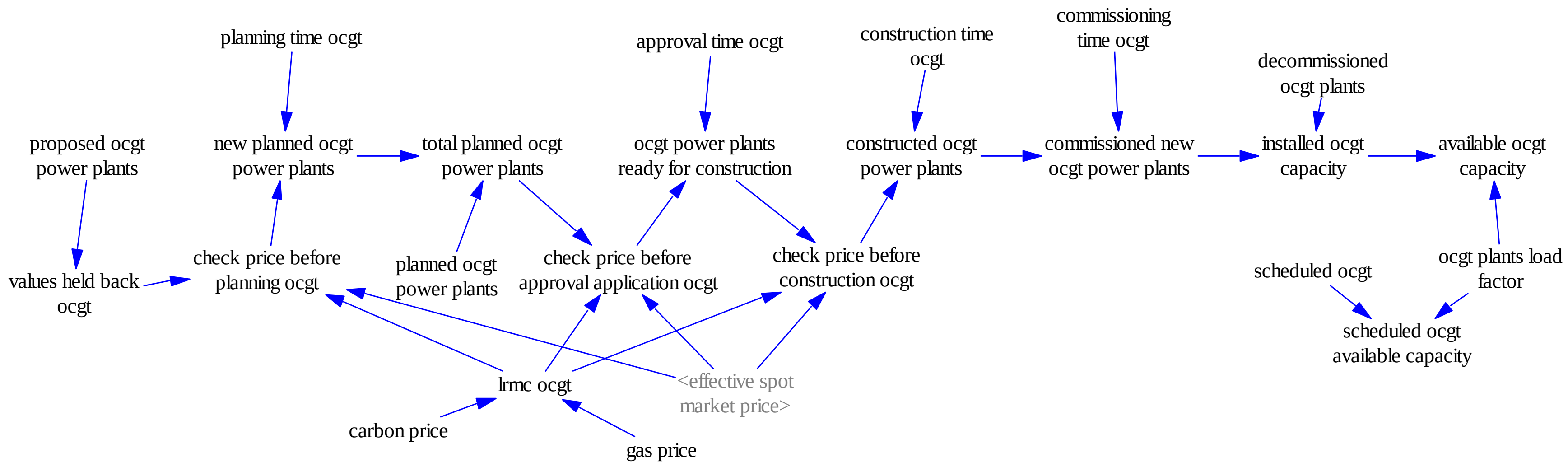


Figure A. 64: Model for OCGT plants development

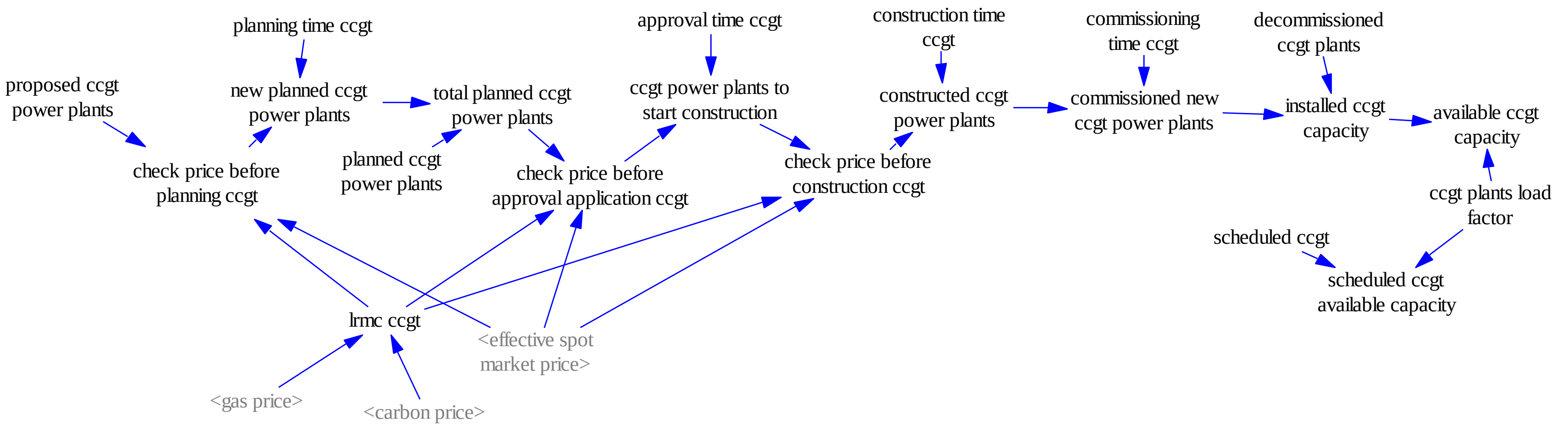


Figure A. 65: Model for CCGT plant development

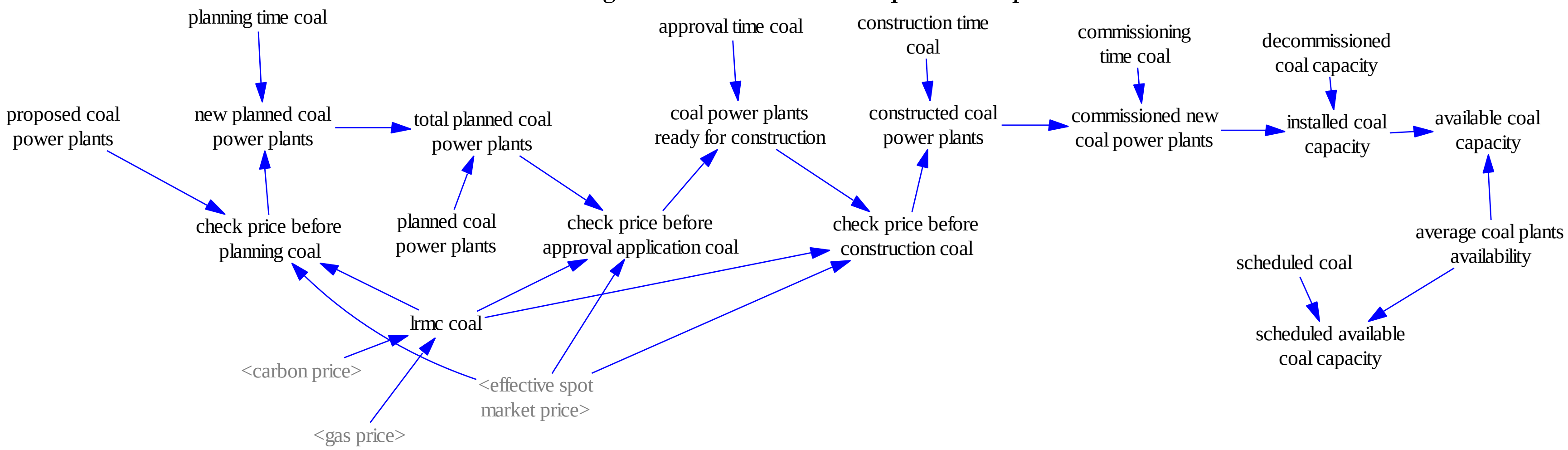


Figure A. 66: Model for coal plant development

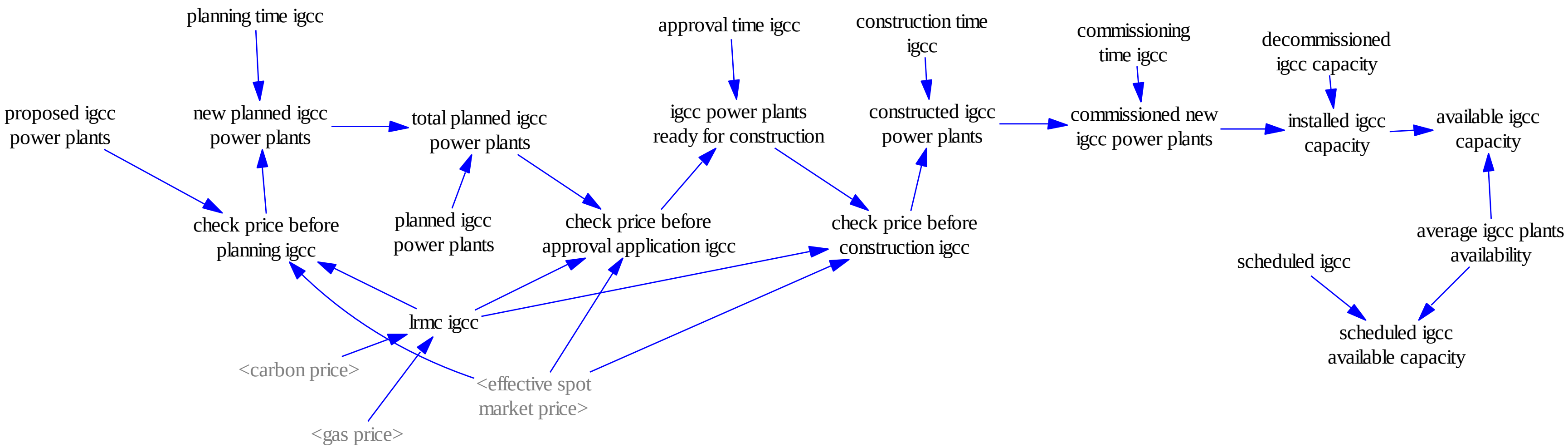


Figure A. 67: Model for IGCC plants development

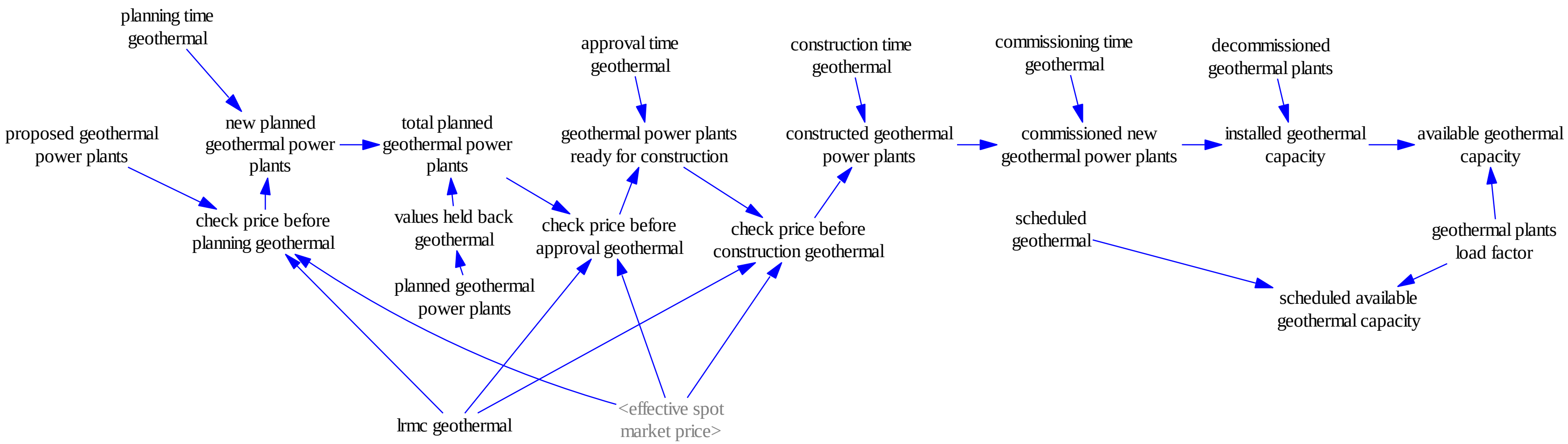


Figure A.68: Model for geothermal plants development

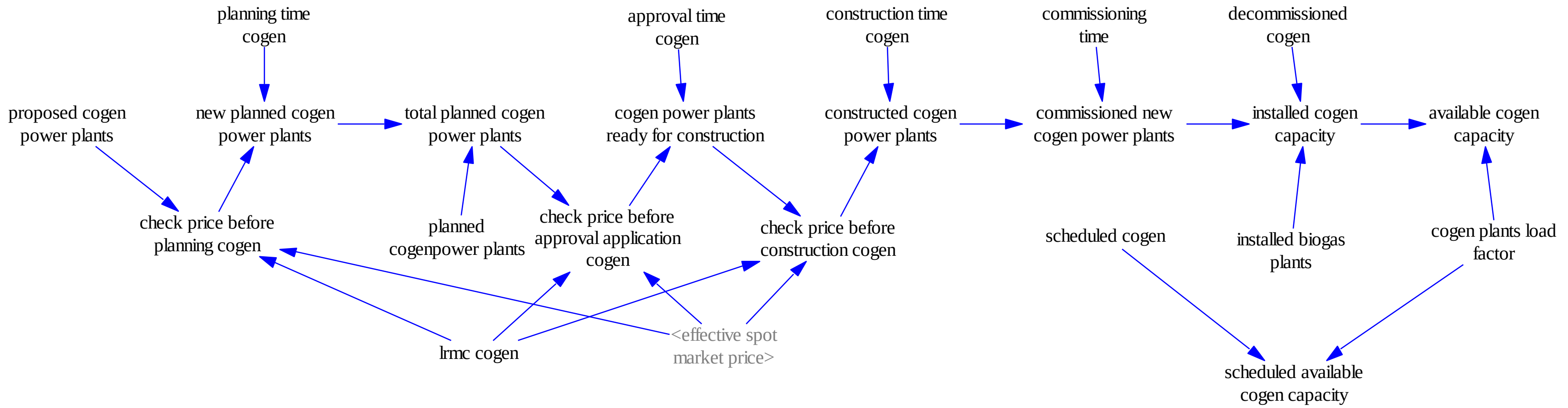


Figure A. 69: Model for cogeneration plants development

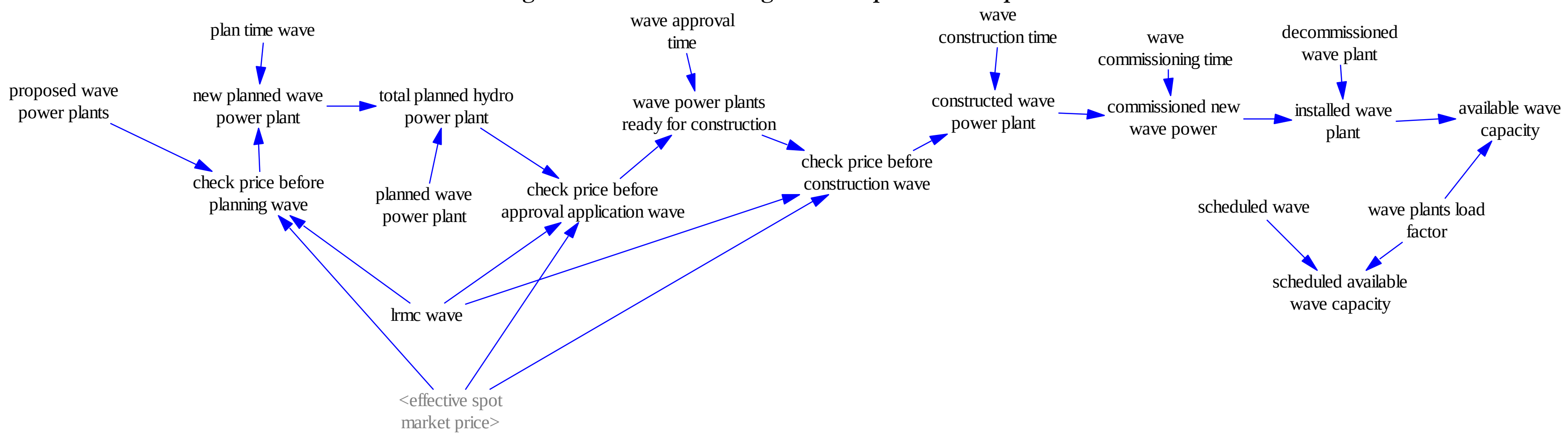


Figure A. 70: Model for wave plants development

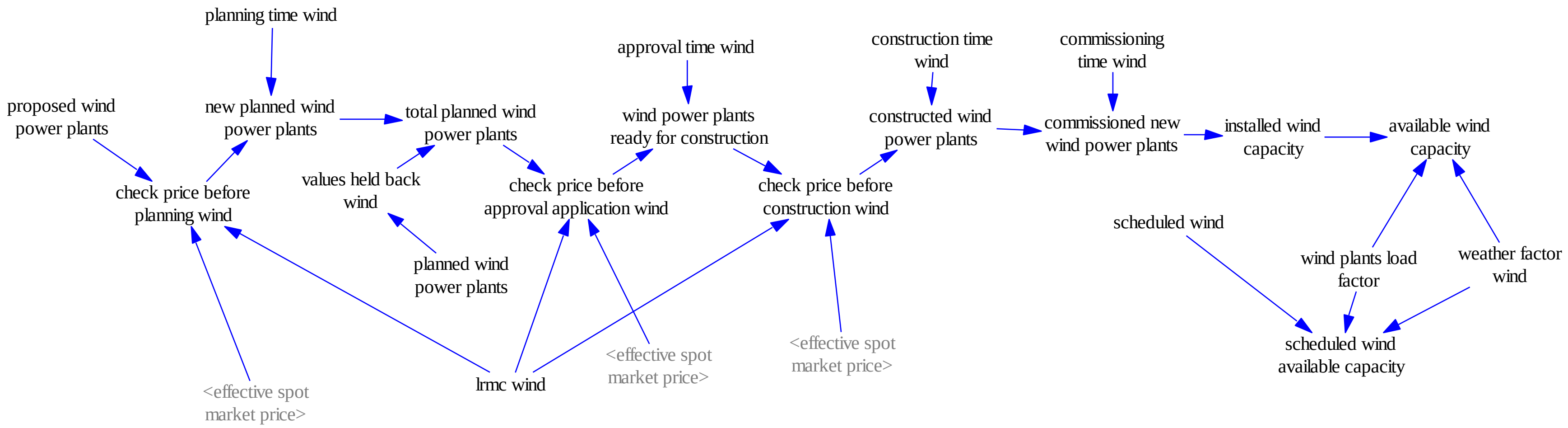


Figure A. 1: Model for wind plants development

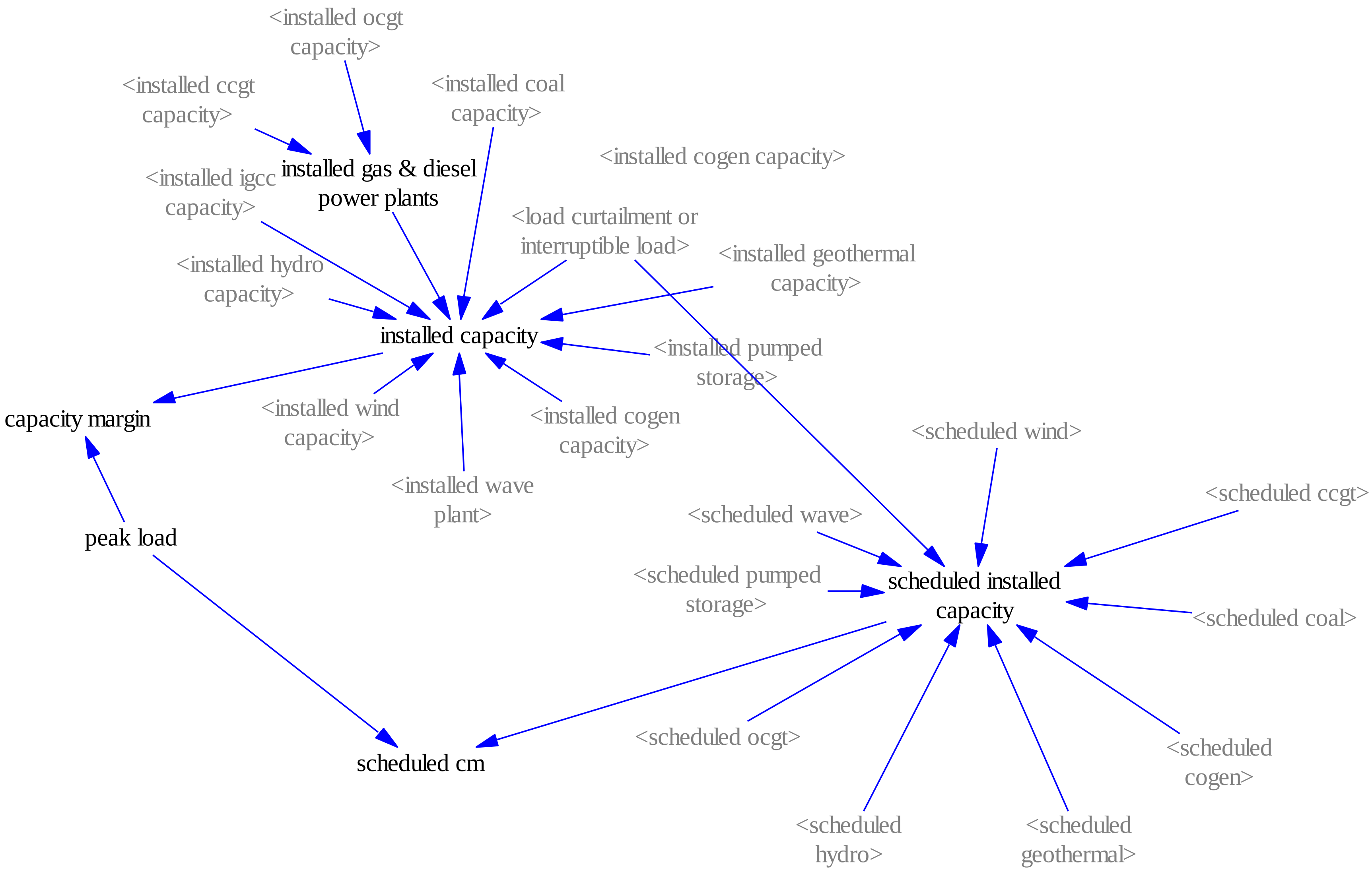


Figure A. 72: Model for calculating total capacity and comparing the SD model output against GEM output

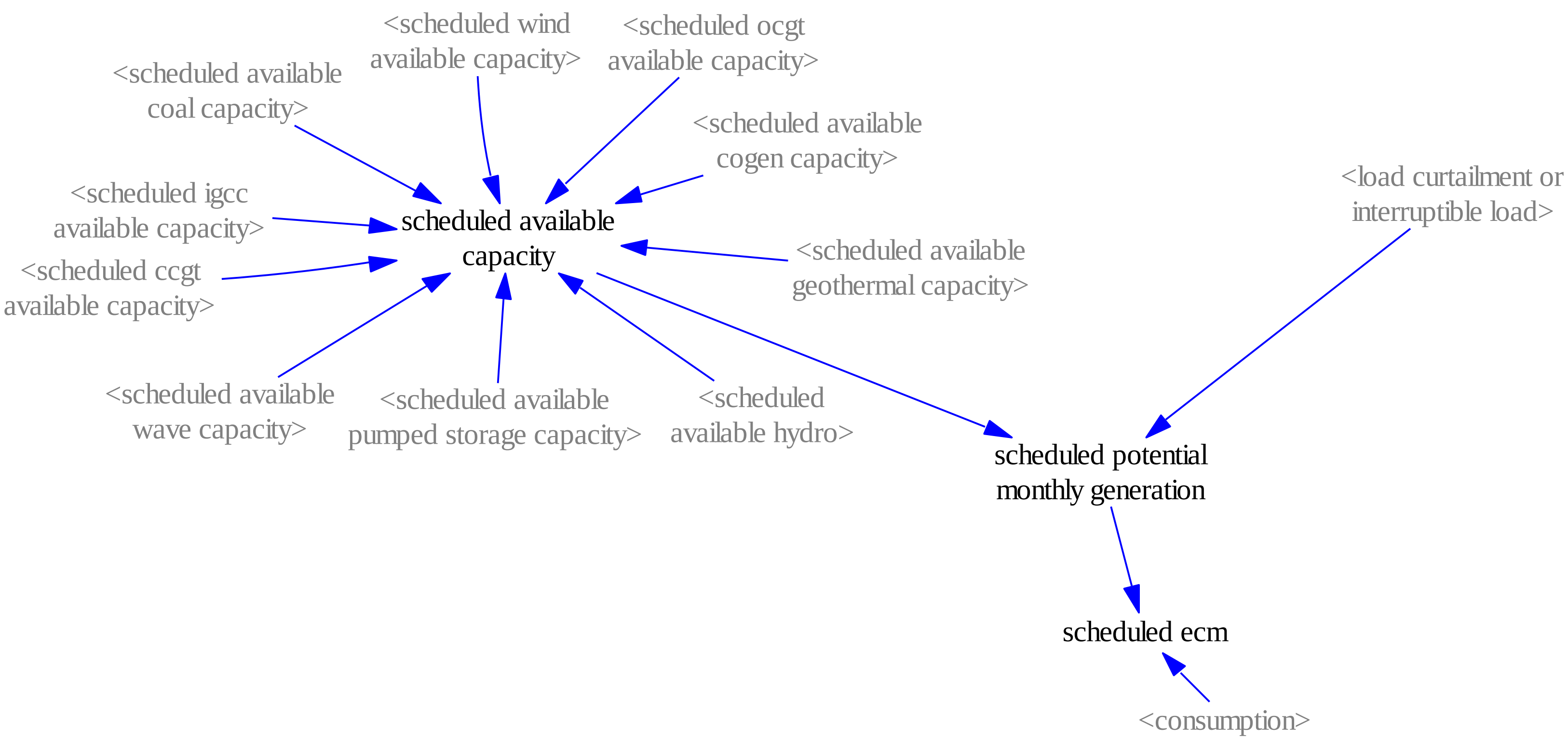


Figure A. 73: Model to calculate energy generation outputs of GEM (to make comparison with SD model outputs)

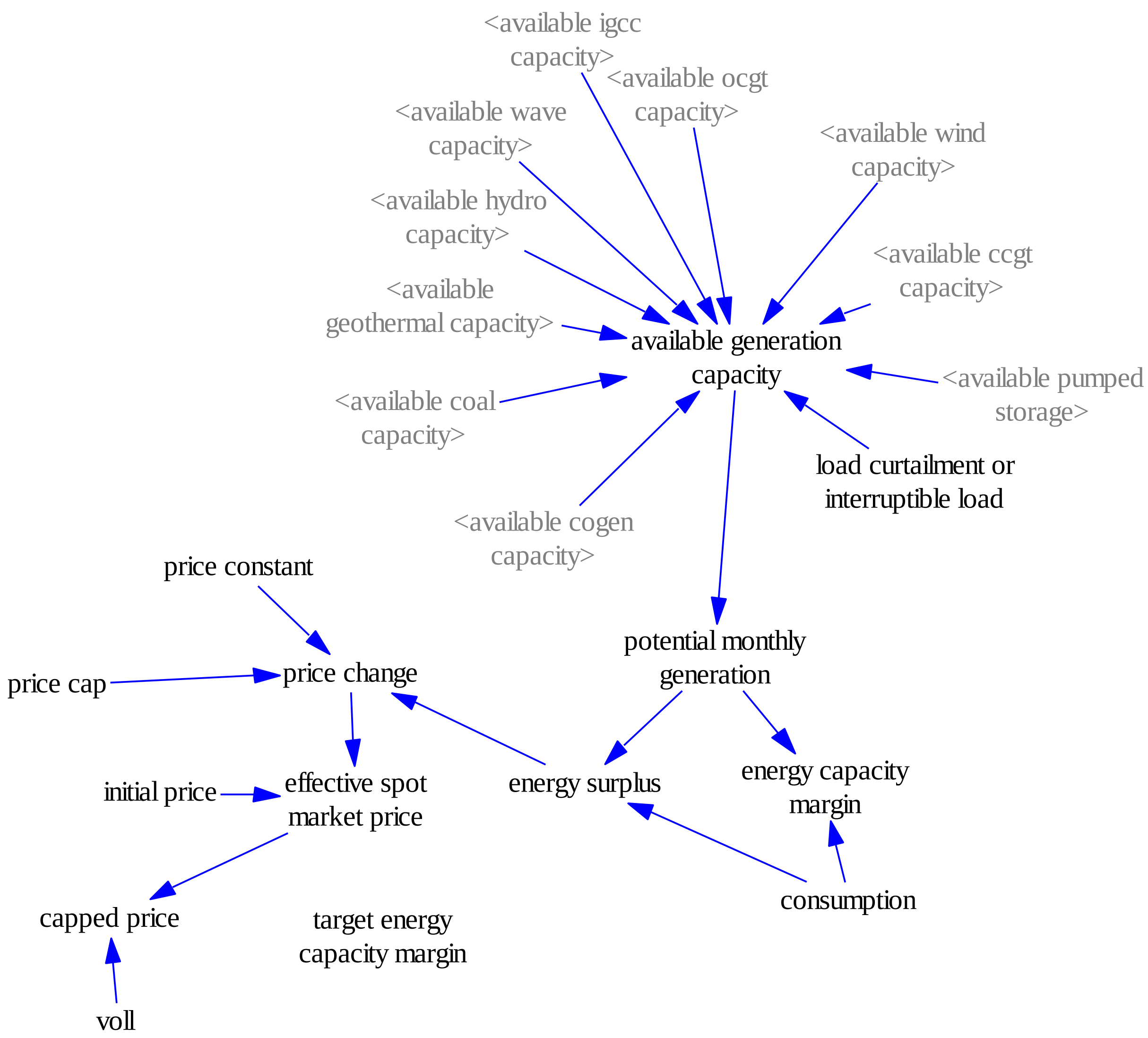


Figure A. 74: Model to determine market price